Virginia Title V Operating Permit

Until such time as this permit is reopened and revised, modified, revoked, terminated or expires, the permittee is authorized to operate in accordance with the terms and conditions contained herein. This permit is issued under the authority of Title 10.1, Chapter 13, §10.1-1322 of the Air Pollution Control Law of Virginia. This permit is issued consistent with the Administrative Process Act, and 9 VAC 5-80-50 through 9 VAC 5-80-300 of the State Air Pollution Control Board's Regulations for the Control and Abatement of Air Pollution (Regulations) of the Commonwealth of Virginia.

Authorization to operate a Stationary Source of Air Pollution as described in this permit is hereby granted to:

Permittee Name: Gordonsville Energy, L. P.
Facility Name: Gordonsville Energy, L. P.
Facility Location: 115 Red Hill Road
Gordonsville, Virginia
Registration Number: 40808
Permit Number: FSO40808

September 5, 2003
Effective Date

September 5, 2008
Expiration Date

Robert G. Burnley
Director, Department of Environmental Quality

Date of Signature

Permit: 57 pages.

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I. FACILITY INFORMATION

Permittee
Gordonsville Energy, L. P.
115 Red Hill Road
Gordonsville, Virginia 22942

Responsible Official
Mr. Ian Cuthbertson
Plant Manager

Facility
Gordonsville Energy L. P.
115 Red Hill Road
Gordonsville, Virginia 22942

Contact Person
Mr. Andrew Hight
Plant Engineer
(540) 832-5672

AIRS Identification Number: 51-109-0040

Facility Description: SIC 4911- Electrical Services. The Gordonsville Energy L. P. facility is an intermediate load, dispatchable, cogeneration power plant that produces electricity for sale to Virginia Dominion Electric Power Company and steam for a host plant. The facility consists of: two GE Frame 7EA combustion turbines (CT) and electricity generators (CTG); two supplementary firing duct burners; one auxiliary boiler; two steam turbines and electricity generators (STG); a fuel oil storage tank; a diesel engine driven fire suppression water pump; and various insignificant emission units as specified in this permit. The primary fuel for the facility is natural gas and the backup fuel is distillate fuel oil.

II. Emission Units

Equipment to be operated consists of:

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity*	Pollution Control Device (PCD) Description	PCD ID	Pollu Contr
Fuel Burning Equipment						
I-A	1	GE Frame 7EA Stationary Combustion Turbine (CT) firing natural gas fuel, and backup distillate oil fuel. Date of Construction: February 1, 1993.	1335 mmBtu/hr burning natural gas at ambient air temperature of 0 °F. 1191 mmBtu/hr burning distillate fuel oil at ambient air temperature of 0 °F. 1154 mmBtu/hr burning natural gas at ambient air temperature of 59 °F. 1026 mmBtu/hr burning distillate fuel oil at ambient air temperature of 59 °F.	Dry Low NOx (DLNOx) combustors when burning natural gas. Water injection when burning distillate fuel oil. Selective Catalytic Reduction (SCR) for NOx emissions, manufactured by Mitsubishi Heavy Industries, Ltd. Date of Construction: February 1, 1993.	201	N
I-B	1	Heat Recovery Steam Generator (HRSG) with Supplementary Duct Burner (DB). Date of Construction: February 1, 1993.	174.7 mmBtu/hr burning natural gas. 166.6 mmBtu/hr burning distillate fuel oil.	SCR for NOx emissions, manufactured by Mitsubishi Heavy Industries, Ltd. Date of Construction: February 1, 1993.	201	N
II-A	2	GE Frame 7EA Stationary	1335 mmBtu/hr burning natural gas at ambient air	DLNOx combustors when burning natural gas. Water	202	N

		Combustion Turbine (CT) firing natural gas fuel, and backup distillate oil fuel. Date of Construction: February 1, 1993.	temperature of 0 °F. 1191 mmBtu/hr burning distillate fuel oil at ambient air temperature of 0 °F. 1154 mmBtu/hr burning natural gas at ambient air temperature of 59 °F. 1026 mmBtu/hr burning distillate fuel oil at ambient air temperature of 59 °F.	injection when burning distillate fuel oil. SCR for NOx emissions, manufactured by Mitsubishi Heavy Industries, Ltd. Date of Construction: February 1, 1993.		
II-B	2	Heat Recovery Steam Generator (HRSG) with Supplementary Duct Burner (DB). Date of Construction: February 1, 1993.	174.7 mmBtu/hr burning natural gas. 166.6 mmBtu/hr burning distillate fuel oil.	SCR for NOx emissions, manufactured by Mitsubishi Heavy Industries, Ltd. Date of Construction: February 1, 1993.	202	N
III	3	International Boiler Works (IBW)/Volcano auxiliary boiler. Date of Construction: February 1, 1993	22 mmBtu/hr	Proper Maintenance and Operation	-	-

*The Size/Rated capacity is provided for informational purposes only, and is not an applicable requirement.

III. Emission Units

Combustion Turbine and Heat Recovery Steam Generator Duct Burner (Emission Unit ID#s I-A and I-B);
Combustion Turbine and Heat Recovery Steam Generator Duct Burner (Emission Unit ID#s II-A and II-B);
Auxiliary Boiler (Emission Unit ID# III);
Distillate Fuel Oil Tank (Emission Unit ID# TK-101);
Diesel Driven Fire Suppression Pump (Emission Unit ID# DP-1)

A. Limitations

1. **Emission Controls** – Nitrogen oxide (NOx) emissions from each CT/HRSG DB (Emission Unit ID#s I-A, I-B, and II-A, II-B) shall be controlled by selective catalytic reduction (SCR). In addition to the SCR control, NOx from each CT (Emission Unit ID#s I-A and II-A) shall be controlled by the utilization of a low NOx burner design when firing natural gas or by water injection when firing Numbers 1 and 2 distillate fuel oil. The CTs (Emission Unit ID#s I-A and II-A), HRSG DBs (Emission Unit ID#s I-B and II-B), and the SCR units shall be provided with adequate access for inspection.
(9 VAC 5-80-110, 9 VAC 5-50-260 and Condition 3 of May 15, 2003, Permit)

2. **SCR Control Device Operation** - Except during CT (Emission Unit ID#s I-A and II-A) start-up/shut-down and transient conditions, the SCR unit shall be operating any time a CT is burning fuel. The SCR unit may operate during CT start-up and transient conditions. CT (Emission Unit ID#s I-A and II-A) start-up begins when a flame is detected. CT start-up ends one hour after ammonia injection begins. The CT start-up time period shall not exceed 6 hours. During CT (Emission Unit ID#s I-A and II-A) shut-down, the permittee shall discontinue use of the SCR (discontinue ammonia injection) when the catalyst bed temperature drops below the predetermined temperature level, but not more than 3 hours prior to the time at which the fuel feed to the CT is discontinued.
(9 VAC 5-80-110, 9 VAC 5-50-260, and Condition 4 of May 15, 2003, Permit)

3. **Emission Controls** – Nitrogen oxide emissions from the auxiliary boiler (Emission Unit ID# III), shall be controlled by the use of low NOx burners and good operating practices.
(9 VAC 5-80-110, 9 VAC 5-50-260 and Condition 5 of May 15, 2003, Permit)

4. **Emission Controls** – Sulfur dioxide (SO_2) emissions from each CT/HRSG DB (Emission Unit ID#s I-A, I-B, and II-A, II-B) and the auxiliary boiler

(Emission Unit ID# III) shall be controlled by the use of very low sulfur fuels (as defined in 40 CFR 60.41b).
(9 VAC 5-80-110, 9 VAC 5-50-260, and Condition 6 of May 15, 2003, Permit)

5. **Emission Controls** – Particulate matter (PM) emissions from each CT/HRSG DB (Emission Unit ID#s I-A, I-B, and II-A, II-B) and the auxiliary boiler (Emission Unit ID# III) shall be controlled by the use of clean burning fuels.
(9 VAC 5-80-110, 9 VAC 5-50-260 and Condition 7 of May 15, 2003, Permit)

6. **Emission Controls** – Carbon monoxide (CO) and volatile organic compound (VOC) emissions from each CT/HRSG DB (Emission Unit ID#s I-A, I-B, and II-A, II-B) and the auxiliary boiler (Emission Unit ID# III) shall be controlled by the use of good combustion operating practices.
(9 VAC 5-80-110, 9 VAC 5-50-260, and Condition 8 of May 15, 2003, Permit)

7. **Fuel Tank** - The on site 5,000,000 gallon fixed roof storage tank (Emission Unit ID# TK-101) shall be used to store Numbers 1 and 2 distillate fuel oil only. Records showing the dimensions of the storage tank and an analysis showing the capacity of the tank shall be accessible at the plant site. The true vapor pressure of the volatile organic liquid stored in the tank shall not exceed 5.14 KPa.
(9 VAC 5-80-110, 40 CFR 60 Subpart Kb, 9 VAC 5-50-410 Subpart Kb, and Condition 9 of May 15, 2003, Permit)

Compliance with the requirement to store Numbers 1 and 2 distillate fuel oil only in the storage tank shall be demonstrated by obtaining and maintaining fuel supplier certifications stating oil delivered to the tank complies with the American Society for Testing and Materials (ASTM) D396-78 definition of Numbers 1 or 2 fuel oil. Certifications stating the oil delivered to the tank is Number 1 or 2 distillate oil demonstrates the true vapor pressure of the volatile organic liquid stored is less than 5.14 KPa.

8. **Process Limitation** - The total amount of the natural gas consumed by the facility, consisting of two CT/HRSG DB (Emission Unit ID#s I-A, I-B, and II-A, II-B) units and an auxiliary boiler (Emission Unit ID# III) shall not exceed 1.33113×10^{10} scf per consecutive 365 day period.
(9 VAC 5-80-110, 9 VAC 5-80-10 H, and Condition 10 of May 15, 2003, Permit)

9. **Process Limitation** - The total amount of Numbers 1 and 2 distillate fuel oil consumed by the facility, consisting of two CT/HRSG DB units (Emission Unit ID#s I-A, I-B, and II-A, II-B), an auxiliary boiler (Emission Unit ID# III), and a diesel engine driven fire suppression pump (Emission Unit ID# DP-1) shall

not exceed 7.4407 x 10^7 gallons per consecutive 365 day period.
(9 VAC 5-80-110, 9 VAC 5-80-10 H, and Condition 11 of May 15, 2003, Permit)

10. **Process Limitation** - The total amount of Numbers 1 and 2 distillate fuel oil consumed by the diesel driven fire suppression water pump (Emission Unit ID# DP-1) shall not exceed 700 gallons per consecutive 12 month period of non-emergency operation. This fuel consumption limitation is applicable to non-emergency operation of the diesel engine.
(9 VAC 5-80-110, 9 VAC 5-80-10 H, and Condition 12 of May 15, 2003, Permit)

11. **Process Limitation** - The total heat input rate of all HRSG duct burners (Emission Unit ID#s I-B and II-B) and the auxiliary boiler (Emission Unit ID# III) shall not exceed 249.9 million Btu per hour, when fired simultaneously or separately. The total heat input rate shall be determined hourly.
(9 VAC 5-80-110 and Condition 13 of May 15, 2003, Permit)

12. **Process Limitation** - Steam produced by the auxiliary boiler (Emission Unit ID# III) shall not be used in a steam turbine to generate electricity.
(9 VAC 5-80-110 and Condition 14 of May 15, 2003, Permit)

13. **Process Limitation** - A CT (Emission Unit ID#s I-A and II-A) and its associated HRSG DB (Emission Unit ID#s I-B and II-B) shall burn the same type fuel.
(9 VAC 5-80-110 and Condition 15 of May 15, 2003, Permit)

14. **Fugitive VOC Emission Controls** - Fugitive VOC emission controls shall include the following, or equivalent, as a minimum:

    Volatile organic compounds shall not be intentionally spilled, discarded in sewers which are not connected to a treatment plant, or stored in open containers or handled in any other manner that would result in evaporation beyond that consistent with air pollution control practices for minimizing emissions.
    (9 VAC 5-80-110, 9 VAC 5-50-260, 9 VAC 5-50-20 F, and Condition 16 of May 15, 2003, Permit)

15. **Fuel Specification** - The approved fuels for each CT (Emission Unit ID#s I-A and II-A), HRSG DB (Emission Unit ID#s I-B and II-B), and auxiliary boiler (Emission Unit ID# III) are natural gas and Numbers 1 and 2 distillate fuel oil. The approved fuel for the diesel engine (Emission Unit ID# DP-1) emergency fire pump is Numbers 1 and 2 distillate fuel oil.

Distillate oil is defined as fuel oil that meets the specifications for fuel oil Numbers 1 and 2 under the American Society for Testing and Materials, ASTM D396-78 "Standard Specification for Fuel Oils", or other approved ASTM method, incorporated in 40 CFR 60 by reference. A change in fuel may require a permit to modify and operate. Records of all fuel supplier certifications shall be available for inspection and shall be current for the most recent five years.
(9 VAC 5-80-110, 9 VAC 5-50-260, 9 VAC 5-50-410 Subparts Db and Dc, 40 CFR 60 Subparts Db and Dc, and Condition 17 of May 15, 2003, Permit)

16. **Fuel Specification** - The maximum sulfur content of the natural gas burned in each CT (Emission Unit ID#s I-A and II-A), HRSG DB (Emission Unit ID#s I-B and II-B), and auxiliary boiler (Emission Unit ID# III) shall not exceed 20 grains/100 dscf.

The natural gas burned in each CT (Emission Unit ID#s I-A and II-A), HRSG DB (Emission Unit ID#s I-B and II-B), and auxiliary boiler (Emission Unit ID# III) shall not exceed an annual weighted average sulfur content of 0.5 grains/100 dscf, calculated daily on a rolling consecutive 365 day period. The annual weighted average sulfur content of the natural gas fuel burned is calculated as follows:

$$\frac{\sum_{t=1}^{365} x_t \frac{(grains\ sulfur)}{(100\, dscf\ of\ gas)} \times z_t\ \ (dscf\ \ gas)}{\sum_{t=1}^{365} z_t\, (dscf\ \ gas)}$$

where

t = numerical day within a consecutive 365 day period;

x_t = the sulfur content of the natural gas sample collected during day t. If a measurement of x_t was not performed during day t, assume x_t is equivalent to the most recent measurement of x_t prior to the beginning of day t;

z_t = the quantity of natural gas burned within a consecutive 365 day period and between the time period of (t-1) and t.

Compliance shall be demonstrated through monitoring of the sulfur content of the natural gas in accordance with the monitoring plan contained in this permit.
(9 VAC 5-80-110, 9 VAC 5-80-10H, and Condition 18 of May 15, 2003, Permit)

17. **Fuel Specification** - The maximum as-fired sulfur content of the Numbers 1 and 2 distillate fuel oil burned in each CT (Emission Unit ID#s I-A and II-A), HRSG DB (Emission Unit ID#s I-B and II-B), and auxiliary boiler (Emission Unit ID# III) shall not exceed 0.05 percent by weight. Compliance shall be demonstrated through fuel supplier certification of sulfur content or through sampling, testing, and certification of as-fired Numbers 1 and 2 distillate fuel oil sulfur content. The Numbers 1 and 2 distillate oil sulfur analysis may be performed by the permittee, a service contractor retained by the permittee, or other DEQ approved agency.
(9 VAC 5-80-110, 9 VAC 5-80-10H, and Condition 19 of May 15, 2003, Permit)

18. **Fuel Specification** - The measured HHV of the natural gas fuel burned in each CT (Emission Unit ID#s I-A and II-A), each HRSG DB (Emission Unit ID#s I-B and II-B) and the auxiliary boiler (Emission Unit ID# III) shall be greater than or equal to 967 Btu/scf.

    The measured HHV of the Numbers 1 and 2 distillate fuel oil burned in each CT (Emission Unit ID#s I-A and II-B), each HRSG DB (Emission Unit ID#s I-B and II-B) and the auxiliary boiler (Emission Unit ID# III) shall be greater than or equal to 132,000 Btu/gallon.
    (9 VAC 5-80-110 and Condition 20 of May 15, 2003, Permit)

19. **Fuel Certification** - The permittee shall obtain a certification from the fuel supplier with each shipment of Numbers 1 and 2 distillate fuel oil. Each fuel supplier certification shall include the following for all Numbers 1 and 2 distillate fuel oil burned in the HRSG DBs (Emission Unit ID#s I-B and II-B), and auxiliary boiler (Emission Unit ID# III):

    a. the name of the fuel supplier;

    b. the date on which the Numbers 1 and 2 distillate fuel oil was received;

    c. the volume of Numbers 1 and 2 distillate fuel oil delivered in the shipment;

    d. a statement that the Numbers 1 and 2 distillate fuel oil complies with the American Society for Testing and Materials specification D396-78 for Numbers 1 and 2 fuel oil; and

    e. the sulfur content of the Numbers 1 and 2 distillate fuel oil.

    Item e. shall be determined and certified for each shipment of Numbers 1 and 2 distillate fuel oil when fuel supplier certification is used to comply with fuel sulfur content requirements of 9 VAC 5-50-410 (40 CFR 60 Subpart Db and Subpart Dc).

Prior to changing to or from permittee analysis of as-fired distillate fuel oil sulfur content versus fuel supplier certification of distillate fuel oil sulfur content, the permittee shall obtain approval from the DEQ, Fredericksburg office to change the method of demonstrating compliance with item e. above.

Numbers 1 and 2 distillate fuel oil sulfur content shall be determined by following procedures identified in ASTM D 2880-71, 78, or 96, or by following an equivalent procedure approved by the DEQ and EPA. If an alternative procedure is used to determine sulfur content in the distillate fuel oil, the procedure shall be submitted for approval by the DEQ, Fredericksburg Office prior to firing the Numbers 1 and 2 distillate fuel oil.

For the purposes of item e. above and for the purpose of 9 VAC 5-50-410 Subparts Db and Dc, the Numbers 1 and 2 distillate fuel oil sulfur content must be 0.5 percent or less by weight. When the permittee tests as-fired Numbers 1 and 2 distillate fuel oil for sulfur content, the permittee shall record and certify the sulfur content test results or obtain documentation and certification of the test results from the testing laboratory. For the purposes of 9 VAC 5-50-410 Subpart Db, the Numbers 1 and 2 distillate fuel oil need not meet the fuel nitrogen content specification of 0.05 or less weight percent nitrogen.

These records shall be available on site for inspection by DEQ personnel. These records shall be kept on file for the most current five year period. (9 VAC 5-80-110, 9 VAC 5-50-410 Subpart Db and Subpart Dc, 40 CFR 60 Subpart Db and Subpart Dc, and Condition 21 of May 15, 2003, Permit)

20. **Combustion Turbine Emission Limits** - Criteria pollutant emissions from the operation (excluding start-up, shut-down, and transient operation) of each CT (Emission Unit ID#s I-A and II-A) shall not exceed the limits specified below:

Natural Gas

Nitrogen Oxides* (as NO_2)	9 ppmdv at 15% O_2* (1-hour average) (9 VAC 5-50-260)
Carbon Monoxide	36 lbs/hr/unit (9 VAC 5-50-260)

Numbers 1 and 2 Distillate Fuel Oil

Nitrogen Oxides* (as NO_2)	12 ppmdv at 15% O_2* (1-hour average) (9 VAC 5-50-260)
Sulfur Dioxide	59 lbs/hr/unit (9 VAC 5-50-260)

Carbon Monoxide	48 lbs/hr/unit (9 VAC 5-50-260)

* Nitrogen oxides concentration (ppm) must be met at all times except during start-up, shut-down, transient operation, or malfunction.
(9 VAC 5-80-110, 9 VAC 5-50-260, and Condition 22 of May 15, 2003, Permit)

Compliance with CT (Emission Unit ID#s I-A and II-A) hourly emission limits for NOx and CO shall be demonstrated by continuous emission monitor systems (CEMS). The CEMS measurement shall be a one-hour average for each CT operating hour. Compliance with the SO_2 hourly emission limit while burning Numbers 1 and 2 distillate fuel oil shall be demonstrated by maintaining records of fuel oil certifications for all Numbers 1 and 2 distillate fuel oil burned and by the following calculation: quantity of Numbers 1 and 2 distillate fuel oil consumed per hour x sulfur content (as SO_2) of the distillate fuel oil (lb SO_2 / lb fuel oil).

The following emission rates are derived from estimated overall emission contributions and are included for inventory purposes only:

Natural Gas

PM-10	4.3×10^{-3} lbs/10^6 BTU	5 lbs/hr/unit
Sulfur Dioxide (annual average)	1.8×10^{-3} lbs/10^6 BTU	2.1 lbs/hr/unit
Nitrogen Oxides (as NO_2)	3.3×10^{-2} lbs/10^6 BTU	44 lbs/hr/unit
Carbon Monoxide		2.8×10^{-2} lbs/10^6 BTU
Volatile Organic Compounds		11 lbs/hr/unit

Numbers 1 and 2 Distillate Fuel Oil

PM-10	9.7×10^{-3} lbs/10^6 BTU	10 lbs/hr/unit
Nitrogen Oxides (as NO_2)	4.9×10^{-2} lbs/10^6 BTU	58 lbs/hr/unit

Sulfur Dioxide	5.0×10^{-2} lbs/10^6 BTU
Carbon Monoxide	4.2×10^{-2} lbs/10^6 BTU
Volatile Organic Compounds	11 lbs/hr/unit
Lead	6.0×10^{-3} lbs/hr/unit

21. **Combustion Turbine and HRSG DB Operation Emission Limits** - Criteria pollutant emissions from the operation (excluding start-up, shutdown, and transient operation) of each CT and its associated HRSG DB (Emission Unit ID#s I-A, I-B, and II-A, II-B) shall not exceed the limits specified below:

Natural Gas

Nitrogen Oxides* (as NO_2)	9 ppmdv at 15% O_2* (1-hour average) (9 VAC 5-50-260)
Carbon Monoxide	57 lbs/hr/unit (9 VAC 5-50-260)

Numbers 1 and 2 Distillate Fuel Oil

Nitrogen Oxides* (as NO_2)	12 ppmdv at 15% O_2* (1-hour average) (9 VAC 5-50-260)
Sulfur Dioxide	68 lbs/hr/unit (9 VAC 5-50-260)
Carbon Monoxide	68 lbs/hr/unit (9 VAC 5-50-260)

*Nitrogen oxides concentration (ppm) must be met at all times except during CT start-up, CT shutdown, CT transient operation, or CT malfunction.

Compliance with CT/HRSG DB (Emission Unit ID#s I-A, I-B, and II-A, II-B) hourly emission limits for NOx and CO shall be demonstrated by CEMS. The CEMS measurement shall be a one-hour average for each CT/HRSG DB operating hour. Compliance with the SO_2 hourly emission limit while burning Numbers 1 and 2 distillate fuel oil shall be demonstrated by maintaining records of distillate fuel oil certifications for all Numbers 1 and 2 distillate fuel oil burned and by the following calculation: quantity of Numbers 1 and 2 distillate fuel oil consumed per hour x sulfur content (as SO_2) of the distillate fuel oil (lb SO_2 / lb fuel oil).
(9 VAC 5-80-110, 9 VAC 5-50-260, and Condition 23 of May 15, 2003, Permit)

The following emission rates are derived from estimated overall emission contributions and are included for inventory purposes only:

Natural Gas

PM-10	6.0×10^{-3} lbs/10^6 BTU	8 lbs/hr/unit
Sulfur Dioxide (annual average)	1.7×10^{-3} lbs/10^6 BTU	2.3 lbs/hr/unit
Nitrogen Oxides (as NO_2)	3.3×10^{-2} lbs/10^6 BTU	50 lbs/hr/unit
Carbon Monoxide		4.0×10^{-2} lbs/10^6 BTU
Volatile Organic Compounds		22 lbs/hr/unit

Numbers 1 and 2 Distillate Fuel Oil

PM-10	1.1×10^{-2} lbs/10^6 BTU	13 lbs/hr/unit
Sulfur Dioxide	5.0×10^{-2} lbs/10^6 BTU	
Nitrogen Oxides (as NO_2)	4.8×10^{-2} lbs/10^6 BTU	66 lbs/hr/unit
Carbon Monoxide		5.2×10^{-2} lbs/10^6 BTU
Volatile Organic Compounds		21 lbs/hr/unit
Lead		6.8×10^{-3} lbs/hr/unit

22. **HRSG Duct Burner Emission Limit** - Criteria pollutant emissions from the operation of each HRSG DB (Emission Unit ID#s I-B and II-B) (excluding CT startup and CT transient operating modes) shall be determined as specified in 40 CFR 60 Subpart Db (40 CFR 60.40b). The emission rate from each DB (Emission Unit ID#s I-B and II-B) shall not exceed the limitations specified below:

Natural Gas and Numbers 1 and 2 Distillate Fuel Oil

Nitrogen Oxides* (as NO_2)	0.2 lbs/10^6 BTU	(30 day rolling average) (9 VAC 5-50-260)

*Nitrogen oxides pounds per million Btu limitation applies at all times including DB startup, shutdown, or malfunction. The emission limit is based on the heat input to the DB.

(9 VAC 5-80-110, 9 VAC 5-50-260, 9 VAC 5-50-410 Subpart Db, 40 CFR 60.40b, and Condition 24 of May 15, 2003, Permit)

Compliance with the HRSG DB (Emission Unit ID#s I-B and II-B) NOx emission limitation shall be demonstrated on a 30-day rolling average basis using a 40 CFR 75 compliant NOx CEMS, except that the permittee shall use missing data substitution procedures in the record keeping section of this permit instead of the missing data substitution procedures identified in 40 CFR 75. A 40 CFR 75 compliant O_2 CEMS shall be co-located with the NOx CEMS. The NOx CEMS shall be operated in accordance with the requirements of 40 CFR 60.48b in addition to 40 CFR 75. The sampling site shall be located at the outlet of the HRSG downstream of the SCR control device. The NOx emission rate at the outlet of the HRSG DB (Emission Unit ID#s I-B and II-B) and downstream of the SCR control device shall constitute the NOx emission rate from the duct burner of the combined cycle system. (9 VAC 5-80-110, 9 VAC 5-50-410, 40 CFR 60.46b (f)(2), and 40 CFR 60.48b, and Condition 24 of May 15, 2003, Permit)

The following emission rates are derived from estimated overall emission contributions and are included for inventory purposes only:

Natural Gas

Nitrogen Oxides (as NO_2)	35 lbs/hr/unit

Numbers 1 and 2 Distillate Fuel Oil

Nitrogen Oxides (as NO_2)	33 lbs/hr/unit

23. **Auxiliary Boiler Emission Inventory** - Criteria pollutant emissions from the operation of the auxiliary boiler (Emission Unit ID # III) are derived from estimated overall emission contributions and are included below for inventory purposes only:

Natural Gas

PM_{10}	5.0×10^{-3} lbs/10^6 BTU	0.11 lbs/hr
Nitrogen Oxides (as NO_2)	1.1×10^{-1} lbs/10^6 BTU	2.4 lbs/hr
Carbon Monoxide	8.2×10^{-2} lbs/10^6 BTU	1.8 lbs/hr
Volatile Organic Compound		0.4 lbs/hr

Numbers 1 and 2 Distillate Fuel Oil

PM_{10}	3.0×10^{-2} lbs/10^6 BTU	0.66 lbs/hr
Sulfur Dioxide	5.0×10^{-2} lbs/10^6 BTU	1.1 lbs/hr
Nitrogen Oxides (as NO_2)	1.7×10^{-1} lbs/10^6 BTU	3.7 lbs/hr
Carbon Monoxide	8.2×10^{-2} lbs/10^6 BTU	1.8 lbs/hr
Volatile Organic Compound		0.55 lbs/hr
Lead		1×10^{-4} lbs/hr

24. **Combustion Turbine Emission Rate Inventory During Start-up and FSNL** - When CEMS data is missing while a CT (Emission Unit ID#s I-A and II-A) is operating in start-up or full speed no load operating modes (see Appendix A), the missing CEMS data shall be substituted with the pollutant's time-averaged emission rate found in Appendix B of this permit for the purpose of demonstrating compliance with facility-wide annual emission limitations.

When a CT is operating in start-up mode, pounds per hour SO_2 emissions shall be calculated by conducting a material balance on sulfur, and pounds per hour VOC and PM_{10} emissions shall be calculated by multiplying the pollutant's time-averaged emission rate found in Appendix B of this permit by the number of hours of CT start-up mode operation. These emissions shall be used in the calculation to demonstrate compliance with the facility-wide annual emission limitations.
(9 VAC 5-80-110 and Condition 26 of May 15, 2003, Permit)

25. **Combustion Turbine Emission Rate Inventory During Transient Operation-** When CEMS data is missing and a CT (Emission Unit ID#s I-A and II-A) is operating in transient operating mode (which includes CT shutdown, fuel switching and power augmentation operating modes as defined in Appendix A), the missing CEMS data shall be substituted with the pollutant's time-averaged emission rate found in Appendix B of this permit for the purpose of demonstrating compliance with facility-wide annual emission limitations.

    When a CT is operating in transient mode, pounds per hour SO_2 emissions shall be calculated by conducting a material balance on sulfur, and pounds per hour VOC and PM_{10} emissions shall be calculated by multiplying the pollutant's time-averaged emission rate found in Appendix B of this permit by the number of hours of CT transient mode operation. These emissions shall be used in the calculation to demonstrate compliance with the facility-wide annual emission limitations.
    (9 VAC 5-80-110 and Condition 27 of May 15, 2003, Permit)

26. **Facility Annual Emission Limitation -** Total facility-wide criteria pollutant emissions shall not exceed the limitations specified below, when summed over any consecutive 365 day period:

Sulfur Dioxide	249.9 tons/yr
Nitrogen Oxides (as NO_2)	245.0 tons/yr
Carbon Monoxide	249.9 tons/yr
Volatile Organic Compounds	97.1 tons/yr
PM_{10}	50.6 tons/yr

    (9 VAC 5-80-110, 9 VAC 5-50-260, and Condition 28 of May 15, 2003, Permit)

    Compliance with the annual NOx and CO emission limits shall be demonstrated on a daily basis by summing emissions of each pollutant over a rolling consecutive 365 day period. Facility-wide NOx and CO annual emission calculations shall include, at minimum, emissions from each CT and CT/HRSG DB (Emission Unit ID#s I-A, I-B, and II-A, II-B), auxiliary boiler (Emission Unit ID# III), and monthly emissions from the diesel engine (Emission Unit ID# DP-1) driven fire suppression water pump.

    The permittee shall collect and record all data necessary to calculate CT and CT/HRSG DB (Emission Unit ID#s I-A, I-B, and II-A, II-B) NOx and CO annual emissions using CEMS data. When valid NOx and CO CEMS data is not available, the default emission rates contained in Appendix B of this permit shall be substituted for the missing CEMS data when calculating annual emissions for compliance purposes.

Compliance with the SO_2 annual emission limit shall be demonstrated on a daily basis by summing emissions over a rolling consecutive 365 day period. The permittee shall collect and record all data necessary to calculate facility-wide annual SO_2 emissions. Emission calculations shall include, at minimum, emissions from each CT and CT/HRSG DBs (Emission Unit ID#s I-A, I-B, and II-A, II-B), auxiliary boiler (Emission Unit ID# III), and monthly emissions from the diesel engine (Emission Unit ID# DP-1) driven fire suppression water pump.

Compliance with the VOC and PM_{10} annual emission limits shall be demonstrated on a daily basis by summing emissions over a rolling consecutive 365 day period. The permittee shall collect and record all data necessary to calculate the facility-wide annual VOC and PM_{10} emissions. VOC and PM_{10} emission calculations shall include, at minimum, emissions from each CT and CT/HRSG DB (Emission Unit ID#s I-A, I-B, and II-A, II-B), auxiliary boiler (Emission Unit ID# III) and monthly emissions from the diesel engine (Emission Unit ID# DP-1) driven fire suppression water pump. Daily emissions of VOC and PM_{10} shall be calculated by summing the following calculation for each emission unit operating in a given day: pollutant specific emission factor (lbs/hour) for each emission unit operating in an Operating Mode found in Appendix B of this permit times the number of operating hours each emission unit operates in the Operating Mode found in Appendix B of this permit.

Emissions generated by each CT during start-up or transient operating modes (as defined in Appendix A) shall be included in the 365 day rolling sum of annual emissions. Daily CT start-up and transient emissions shall be calculated as follows: pollutant specific emission factor (lbs/hour) for each CT operating in an Operating Mode found in Appendix B of this permit times the number of operating hours each CT operates in the Operating Mode found in Appendix B of this permit. Actual valid NOx or CO CEMS emissions or SO_2 emissions determined by material balance may substituted for the NOx, CO, or SO_2 emission factors identified in Appendix B of this permit when determining daily CT start-up and transient mode emissions.

Emissions generated by the diesel engine driven fire suppression water pump shall be calculated using emission factors approved by the DEQ, Fredericksburg Office.

Monthly emissions from the diesel engine (Emission Unit ID# DP-1) driven fire suppression water pump generated during month "X" shall be included in the annual rolling 365 consecutive day emission summation on the last day of month "X".
(9 VAC 5-80-110 and Condition 28 of May 15, 2003, Permit)

The following emission rate is derived from estimated overall emission contributions and are included for inventory purposes only:

Lead	49 lbs/yr

27. **Visible Emission Limit** - Visible emissions (VE) from each CT and CT/HRSG DB (Emission Unit ID#s I-A, I-B and II-A, II-B) exhaust stack shall not exceed ten (10) percent opacity, except during one six-minute period per hour in which opacity shall not exceed twenty-seven (27) percent. The opacity standard shall apply at all times except during periods of startup, shutdown, or malfunction. When a VE evaluation is required, details of VE evaluation shall be arranged with the Air Compliance Manager of the Northern Virginia Regional Office.
(9 VAC 5-80-110, 9 VAC 5-50-260, 9 VAC 5-50-80, 9 VAC 5-50-410 Subpart Db, 40 CFR 60.43b(f), 40 CFR 60 Subpart Db, 9 VAC 5-50-20A and Condition 29 of May 15, 2003, Permit)

28. **Visible Emission Limit** - Visible emissions from the auxiliary boiler (Emission Unit ID# III) exhaust stack shall not exceed ten (10) percent opacity, except during one six-minute period per hour in which opacity shall not exceed twenty (20) percent. Visible emissions from the diesel engine exhaust stack (Emission Unit ID# DP-1) emergency fire pump exhaust stack shall not exceed twenty (20) percent opacity, except during one six-minute period per hour in which opacity shall not exceed thirty (30) percent. The opacity standard shall apply at all times except during periods of startup, shutdown, or malfunction. When a VE evaluation is required, details of VE evaluation shall be arranged with the Air Compliance Manager of the Northern Virginia Regional Office.
(9 VAC 5-80-110, 9 VAC 5-50-260, 9 VAC 5-50-80, 9 VAC 5-50-410 Subpart Dc, 40 CFR 60 Subpart Dc, 9 VAC 5-50-20A, and Condition 30 of May 15, 2003, Permit)

29. **Requirements by Reference -** Except as specified in this permit, the facility is to be operated in compliance with all applicable requirements of each applicable New Source Performance Standard (NSPS) including the following:

    a. 40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines;

    b. 40 CFR Part 60, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units;

c. 40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units;

d. 40 CFR Part 60, Subpart Kb (60.116b, paragraphs (a) and (b)) - Standards of Performance for Volatile Organic Liquid Storage Vessels
(9 VAC 5-80-110, 9 VAC 5-50-410, and Condition 31 of May 15, 2003, Permit)

30. **Major Stationary Source Notification -** The permittee shall report each hour in which the combined heat input of all HRSG DBs (Emission Unit ID#s I-B and II-B) and the auxiliary boiler (Emission Unit # III) exceeds 249.9 million Btu/hr. The report shall be submitted within four business hours and shall include the time and duration when the sum of the emission units heat input exceed 249.9 million Btu/hr, the type of fuel consumed by each emission unit, the rate of fuel consumption (actual volume of fuel consumed per hour), and the HHV of the fuel (per unit volume).
(9 VAC 5-80-110, 9 VAC 5-80-1710, 9 VAC 5-50-50, and Condition 54 of May 15, 2003, Permit)

31. **PSD Applicability -** At such time the permittee requests to amend this permit or to modify the source in a manner which creates a federal major stationary source, the entire source including any modification may be subject to Prevention of Significant Deterioration (PSD) as though construction had not yet commenced on the source or modification. The source will be subject to PSD review if any enforceable limitation on the source's capacity to emit a pollutant is relaxed. Specifically, relaxation of any condition to allow combustion of fossil fuel in a steam generation unit in excess of 250 million BTU/hr or to allow the source to emit more than 249.9 tons/year of any pollutant will subject the entire source to PSD review as though construction had not commenced.
(9 VAC 5-80-110, 40 CFR 52.21r(4), 9 VAC 5-80 Article 8, and Condition 55 of May 15, 2003, Permit)

B. Monitoring

32. **CEMS -** The NOx, CO and oxygen (O_2) emission monitors required by this permit, the continuous monitoring data, and the quality assurance data shall be used to determine compliance with the NOx and CO emission limits and/or relevant emission standards. Each monitor is subject to such data capture requirements and/or quality assurance requirements as specified in this permit and as may be deemed appropriate by the Board. (For each CO CEMS use 40 CFR 60.13 and 40 CFR 60, Appendix B and F. For each NOx and O_2 CEMS use 40 CFR 75 Appendix A and Appendix B)
(9 VAC 5-80-110, 9 VAC 5-50-40, 9 VAC 5-50-410, and Condition 32 of May 15, 2003, Permit)

33. **COMS -** At the discretion of the Board, the opacity emission monitors required by this permit, the continuous monitoring data, and the quality assurance data may be used to determine compliance with the opacity standards. Each continuous opacity monitoring system (COMS) is subject to such data capture requirements and/or quality assurance requirements as specified in this permit and as may be deemed appropriate by the Board. (For each COMS use 40 CFR 60.13 and 40 CFR 60, Appendix B)
(9 VAC 5-80-110 and Condition 33 of May 15, 2003, Permit)

34. **NOx CEMS -** Continuous Emission Monitoring Systems (CEMS) shall be installed to measure and record the emissions of NOx (as NO_2) from each CT/HRSG (Emission Unit ID#s I-A, I-B, and II-A, II-B) exhaust stack. The NOx CEMS shall be located downstream of the selective catalytic reduction system. An O_2 CEMS shall be co-located with each NOx CEMS. The data shall be reduced to one hour averages.

    The CEMS shall be installed, calibrated, maintained, audited, and operated in accordance with performance specifications and test procedures identified in 40 CFR 75. The 40 CFR 75 compliant NOx and O_2 CEMS shall be used to monitor NOx emission from each CT/HRSG (Emission Unit ID#s I-A, I-B, and II-A, II-B) throughout the year. The quality assurance of data generated by the CEMS shall be demonstrated by implementing or exceeding the minimum requirements for CEMS quality assurance as defined in 40 CFR 75, Appendix B, and as may be required by this permit.

    The Fredericksburg Office of the DEQ shall be notified in writing at least thirty days prior to the demonstration of CEMS performance. Subsequent similar notification requirements are to be submitted to the DEQ, Fredericksburg Office.
    (9 VAC 5-80-110, 9 VAC 5-50-40, 9 VAC 5-50-410 Subpart Db, 40 CFR 60 Subpart Db, 40 CFR 60.48b and Condition 34 of May 15, 2003, Permit)

35. **CO CEMS -** CEMS shall be installed to measure and record the emissions of CO from each CT/HRSG DB (Emission Unit ID#s I-A, I-B, and II-A, II-B) exhaust stack. The CO CEMS shall be located downstream of the HRSG DB (Emission Unit ID#s I-B and II-B).

    Except where otherwise indicated in this permit, the CEMS shall be installed, calibrated, maintained, audited and operated in accordance with performance specifications and test procedures identified in 40 CFR 60.13 and 40 CFR Part 60, Appendix B. The quality assurance of data generated by the CEMS shall be demonstrated by implementing or exceeding the minimum requirements for CEMS quality assurance as defined in 40 CFR 60, Appendix F, except where more stringent requirements are specified by this permit. The data shall be reduced to one-hour averages.

The Fredericksburg Office of the DEQ shall be notified in writing at least thirty days prior to the demonstration of CEMS performance. Subsequent similar notification requirements are to be submitted to the DEQ, Fredericksburg Office.
(9 VAC 5-80-110, 9 VAC 5-50-40, 9 VAC 5-50-410, and Condition 35 of May 15, 2003, Permit)

36. **NOx or CO CEMS Data Substitution for Annual Emissions Calculations -** In the event of missing or invalid NOx or CO hourly CEMS data and for the purpose of calculating rolling annual emissions, the permittee shall substitute the emission rate in Appendix B of this permit for the missing NOx or CO CEMS data. The permittee shall identify the operating mode of the CT/HRSG DB (Emission Unit ID#s I-A, I-B, and II-A, II-B) and refer to Appendix B of this permit to obtain the appropriate NOx or CO emission rate. The emission rate selected shall replace the missing data for the purpose of calculating the rolling consecutive 365 day annual emission calculation. This CEMS Data Substitution procedure is not appropriate for nor applicable to the NOx emissions trading program.
(9 VAC 5-80-110 and Condition 36 of May 15, 2003, Permit)

37. **Continuous Monitoring System (CMS) Water to Fuel Ratio** – A continuous monitoring system shall be installed to measure and record the hourly water consumption of each CT (Emission Unit ID#s I-A and II-A). The permittee shall determine the average hourly ratio of water to Numbers 1 and 2 distillate fuel oil burned in each CT (Emission Unit ID#s I-A and II-A). The system shall be accurate to within ±5% and shall be approved by the DEQ, Fredericksburg Office. The monitoring system shall be operated at all times that water is being injected into the CT (Emission Unit ID#s I-A and II-A). The water injection system shall be maintained and calibrated in accordance with manufacturer's specifications. A thirty day notification prior to the demonstration of continuous monitoring system performance and subsequent notification requirements are to be submitted to the DEQ, Fredericksburg Office.
(9 VAC 5-80-110, 9 VAC 5-50-20 C, 9 VAC 5-50-40, 9 VAC 5-50-410 Subpart GG, 40 CFR 60 Subpart GG, 40 CFR 60.334(a)) and Condition 37 of May 15, 2003, Permit)

38. **COMS -** A Continuous Opacity Monitoring Systems (COMS), meeting the design specifications of 40 CFR Part 60, Appendix B, shall be installed to measure and record the opacity of emissions from each CT/HRSG DB (Emission Unit ID#s I-A, I-B, and II-A, II-B). The COMS shall be located downstream of the DB and SCR control device. Except where otherwise indicated in this permit, the COMS shall be installed, calibrated, maintained, and operated in accordance with the requirements of 40 CFR 60.13, 40 CFR

60 Subpart Db, and 40 CFR 60 Appendix B. Data shall be reduced to six-minute averages.

The Fredericksburg Office of the DEQ shall be notified in writing at least thirty days prior to the demonstration of COMS performance. Subsequent similar notification requirements are to be submitted to the DEQ, Fredericksburg Office.
(9 VAC 5-80-110, 9 VAC 5-50-40, 9 VAC 5-50-410 Subpart Db, 40 CFR 60 Subpart Db, 40 CFR 60.48b and Condition 38 of May 15, 2003, Permit)

39. **COMS -** A COMS meeting the design specifications of 40 CFR Part 60, Appendix B, shall be installed to measure and record the opacity of emissions from the auxiliary boiler (Emission Unit ID# III). Except where otherwise indicated in this permit, the COMS shall be installed, calibrated, maintained, audited and operated in accordance with the requirements of 40 CFR 60.13 and 40 CFR 60 Appendix B. Data shall be reduced to six-minute averages. The COMS installed on the auxiliary boiler (Emission Unit # III) exhaust stack shall not be removed without the consent of the DEQ, Fredericksburg Office.
(9 VAC 5-80-110 E and Condition 39 of May 15, 2003, Permit)

40. **CEMS and COMS -** The COMS, NOx CEMS, O_2 CEMS, and CO CEMS required by this permit shall meet a minimum data capture of 95 percent of the facility operating hours, calculated monthly, on a twelve (12) consecutive month rolling period.
(9 VAC 5-80-110 and Condition 40 of May 15, 2003, Permit)

41. **CEMS for HRSG DB NOx Compliance Demonstration -** The NOx CEMS required by this permit shall meet a minimum data capture of 75% of the operating hours in each HRSG DB (Emission Unit ID#s I-B and II-B) steam generating unit operating day, in at least 22 out of 30 successive HRSG DB (Emission Unit ID#s I-B and II-B) steam generating unit operating days.

A "steam generating unit operating day" means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the HRSG DB (steam generating unit). It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

When NOx CEMS data is not obtained due to CEMS breakdown, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7, Method 7A, or other approved reference methods to provide the minimum NOx emissions data capture rate identified in this condition.
(9 VAC 5-80-110, 9 VAC 5-50-410 Subpart Db, 40 CFR 60 Subpart Db, 40 CFR 60.48b (f), and Condition 41 of May 15, 2003, Permit)

42. **Monitoring Devices – Fuel Consumption** – A continuous monitoring system shall be installed to measure the hourly consumption of each fuel (in scf/hour and gallons/hour) by each CT (Emission Unit ID#s I-A and II-A) (40 CFR 60.334) and each HRSG DB (Emission Unit ID#s I-B and II-B). A continuous monitoring system shall be installed to measure the hourly consumption of each fuel (in scf/hour and gallons/hour) by the auxiliary boiler (Emission Unit ID# III) (40 CFR 60.48c).
(9 VAC 5-80-110, 9 VAC 5-80-10 H, 9 VAC 5-50-20 C, 9 VAC 5-50-410 Subparts Dc and GG, 40 CFR 60 Subparts Dc and GG, and Condition 42 of May 15, 2003, Permit)

43. **Monitoring of Natural Gas Fuel -** The permittee shall monitor the sulfur content of the natural gas as-fired in each CT (Emission Unit ID#s I-A and II-A), as-fired in each HRSG DB (Emission Unit ID#s I-B and II-B), and as-fired in the auxiliary boiler (Emission Unit ID# III).

The natural gas sulfur content shall be monitored as follows, pending required approval from the EPA:

a. Analysis for fuel sulfur content of the natural gas shall be conducted, as referenced in 40 CFR 60.334(b)(2), using one of the approved ASTM reference methods, or an approved alternative method, for the measurement of sulfur in gaseous fuels. The reference methods are: ASTM D1072-80; ASTM D3031-81; ASTM D3246-81; and ASTM D4084-82. ASTM D5504 is an approved alternative method to determine sulfur content in gaseous fuels.

b. Sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with the sulfur content permit condition, then sulfur monitoring shall be conducted once per quarter for six quarters.

c. If requested by the permittee, the DEQ may limit the frequency of natural gas sulfur monitoring required by 40 CFR 60 Subpart GG to a minimum of twice per annum provided that the monitoring required in item b. above demonstrates that the sulfur content of the natural gas fuel shows little variability and the monitoring demonstrates compliance with the annual natural gas sulfur content limitation specified in this permit. At a minimum, two of the gas samples collected each year for sulfur monitoring shall be separated by a forty-five day period.

d. Should any sulfur analysis required in items b. or c. above indicate noncompliance, the owner or operator shall notify the DEQ Fredericksburg Office of such emissions and this custom schedule shall be re-examined by the DEQ. While the sulfur monitoring schedule is being re-examined, sulfur monitoring shall be conducted at a minimum rate of once during a rolling period of time consisting of seven (7) unit operating days. For the purposes of this permit condition, a unit operating day is any day during which any CT (Emission Unit ID#s I-A and II-A) burns natural gas.

e. If there is a change in fuel supply, the permittee must notify the DEQ Fredericksburg Office of such change for re-examination of this custom schedule. A substantial change in fuel quality shall be considered a change in fuel supply. Sulfur monitoring shall be conducted weekly during the interim period while this custom schedule is being re-examined.

All of the preceding records shall be available on site for inspection by DEQ personnel. They shall be kept on file for the most recent five year period.
(9 VAC 5-80-110, 9 VAC 5-50-410 Subpart GG, 40 CFR 60 Subpart GG, 40 CFR 60.334(b), and Condition 43 of May 15, 2003, Permit)

44. **Monitoring of Natural Gas HHV -** The permittee shall monitor the HHV of the natural gas burned in the CT (Emission Unit ID#s I-A and II-A), HRSG DB (Emission Unit ID#s I-B and II-B), and auxiliary boiler (Emission Unit ID# III) in accordance with a method and frequency set forth in 40 CFR 75, Appendix D, Section 2.3.4. The HHV of the natural gas shall be determined at least once per month.
(9 VAC 5-80-110 and Condition 44 of May 15, 2003, Permit)

45. **Monitoring of Distillate Oil Fuel -** The permittee shall test the as-fired Numbers 1 and 2 distillate fuel oil for sulfur content and HHV on each occasion that fuel is transferred to the fuel storage tank from any other source. Numbers 1 and 2 distillate fuel oil sulfur content shall be determined using ASTM D2880-71, 78, 96, or by following a DEQ approved equivalent procedure. (9 VAC 5-50-410 Subpart GG, 40 CFR 60.335) The Numbers 1 and 2 distillate fuel oil sulfur analysis may be performed by the permittee, a service contractor retained by the permittee, the fuel vendor, or other DEQ approved agency.

The requirement to monitor the nitrogen content of the Numbers 1 and 2 distillate fuel oil being fired in each CT on each occasion that fuel is transferred to the fuel oil storage tank is waived, provided the CT NOx CEMS required by this permit is maintained in accordance with 40 CFR Part 75 and is fully compliant with 40 CFR 75 and Part 75 data substitution procedures.

The permittee shall submit a plan to the DEQ Fredericksburg Office that specifies the manner in which on-site Numbers 1 and 2 distillate fuel oil will be tested to determine the sulfur content and HHV of the distillate fuel oil. The test methods and changes to the test methods used by the permittee to determine sulfur content and HHV of the Numbers 1 and 2 distillate fuel oil shall be submitted to and approved by the DEQ, Fredericksburg Office prior to burning distillate oil tested by the proposed methods.

Records of the Numbers 1 and 2 distillate fuel oil sulfur content and HHV shall be available on site for inspection by the DEQ. They shall be kept on file for the most current five year period.
(9 VAC 5-80-110, 9 VAC 5-50-410 Subpart GG, 40 CFR 60 Subpart GG, 40 CFR 60.334(b) and Condition 45 of May 15, 2003, Permit)

46. **Monitoring of HRSG DB -** The permittee shall use the 40 CFR 75 compliant NOx CEMS to monitor the NOx emissions generated by each HRSG DB (Emission Unit ID#s I-B and II-B). The NOx CEMS shall be operated and data recorded during all periods of operation of the HRSG DB (Emission Unit ID#s I-B and II-B) except for CEMS breakdowns and repairs. Data shall be recorded during calibration checks, and zero and span adjustments.
(9 VAC 5-80-110, 9 VAC 5-50-410 Subpart Db, 40 CFR 60 Subpart Db, 40 CFR 60.48b(c), and Condition 46 of May 15, 2003, Permit)

The NOx CEMS results shall be reported in units of lb/million Btu heat input and shall be used to calculate the average 1-hour NOx emission rate of each HRSG DB (Emission Unit ID#s I-B and II-B). At least 2 data points must be used to calculate each 1-hour average.
(9 VAC 5-80-110, 9 VAC 5-50-410 Subpart Db, 40 CFR 60 Subpart Db, 40 CFR 60.48b (d), and Condition 46 of May 15, 2003, Permit)

C. Recordkeeping

47. On Site Records for 9 VAC 5-50-410 Subparts Db, Dc and GG - The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit and to support the reporting requirements specified in 40 CFR 60. The content and format of such records shall be arranged with the DEQ, Fredericksburg Office. These records shall include, but are not limited to:

CT Records - 9 VAC 5-50-410 Subpart GG

a. The hourly water injection rate and hourly fuel consumption rate of each CT (Emission Unit ID#s I-A and II-A); in accordance with Applicability Determination Index (ADI) Control Number 0200080, item 4, the hourly water injection rate need not be recorded or reported if the CT NOx CEMS required by this permit is maintained in accordance with 40 CFR Part 75 and is fully compliant with 40 CFR 75 and Part 75 data substitution procedures;
(9 VAC 5-80-110, 9 VAC 5-50-410 Subpart GG, 40 CFR 60 Subpart GG, 40 CFR 60.334(a), and Condition 47 of May 15, 2003, Permit)

b. The requirement to calculate, record, and report the hourly water-to-fuel ratio of water and fuel consumed by each CT (Emission Unit ID#s I-A and II-A) when burning fuel oil is waived, provided the CT NOx CEMS required by this permit is maintained in accordance with 40 CFR Part 75 and is fully compliant with 40 CFR 75 and Part 75 data substitution procedures;
(9 VAC 5-80-110, 9 VAC 5-50-410 Subpart GG, 40 CFR 60 Subpart GG, 40 CFR 60.334(a), and Condition 47 of May 15, 2003, Permit)

c. Hourly average of CEMS measurements for NOx, O_2, and CO emissions from each CT or CT/HRSG DB (Emission Unit ID#s I-A, I-B, and II-A, II-B);
(9 VAC 5-80-110, 9 VAC 5-50-410 Subpart GG, 40 CFR 60 Subpart GG, 40 CFR 60.334(a), and Condition 47 of May 15, 2003, Permit)

d. Records of the sulfur content of fuel combusted in the CT (Emission Unit ID#s I-A and II-A). Records shall be maintained for each occasion the fuel sulfur content is monitored.
(9 VAC 5-80-110, 9 VAC 5-50-410 Subpart GG, 40 CFR 60 Subpart GG, 40 CFR 60.334, and Condition 47 of May 15, 2003, Permit)

HRSG DB Records - 9 VAC 5-50-410 Subpart Db

e. Records of the amount of each fuel combusted in each HRSG DB (Emission Unit ID#s I-B and II-B) on a daily basis. The permittee shall calculate and record the annual capacity factor (see 40 CFR 60 Subpart Db) of each HRSG DB (Emission Unit ID#s I-B and II-B) on a 12-month rolling basis for each fuel burned. A new annual capacity factor shall be calculated at the end of each calendar month.
(9 VAC 5-80-110, 9 VAC 5-50-410 Subpart Db, 40 CFR 60 Subpart Db, 40 CFR 60.49b), and Condition 47 of May 15, 2003, Permit)

f. Records of CT/HRSG DB (Emission Unit ID#s I-A, I-B and II-A, II-B) opacity measurement obtained by the COMS and by Method 9 opacity observations.
(9 VAC 5-80-110, 9 VAC 5-50-410 Subpart Db, 40 CFR 60 Subpart Db, 40 CFR 60.49b, and Condition 47 of May 15, 2003, Permit)

g. Records of Numbers 1 and 2 distillate fuel oil supplier certifications for all Numbers 1 and 2 distillate fuel oil burned in the HRSG DBs (Emission Unit ID#s I-B and II-B). Numbers 1 and 2 distillate oil burned in the HRSG DBs (Emission Unit ID#s I-B and II-B) need not meet the fuel nitrogen content specification defined in 40 CFR 60.41b (ASTM D396-78 for Numbers 1 or 2 distillate fuel oil).
(9 VAC 5-80-110, 9 VAC 5-50-410 Subpart Db, 40 CFR 60 Subpart Db, 40 CFR 60.41b, 40 CFR 60.49b, and Condition 47 of May 15, 2003, Permit)

h. NOx CEMS data recorded and reported for each HRSG DB (Emission Unit ID#s I-B and II-B) shall not include data substitution based on the missing data procedures in 40 CFR 75 Subpart D, nor shall the data substitution include data that has been bias adjusted according to the procedures of 40 CFR 75.
(9 VAC 5-80-110, 9 VAC 5-50-410 Subpart Db, 40 CFR 60 Subpart Db, 40 CFR 60.48b and 60.49b, and Condition 47 of May 15, 2003, Permit)

i. Daily records of the following information for each HRSG DB steam generating unit operating day. Quarterly reports containing the information shall be submitted to the DEQ, Fredericksburg Office and the EPA, postmarked no later than the 30th day following the end of the calendar quarter:

(1) Calendar date.

(2) The average hourly NOx emission rates (expressed as NO_2) (lb/million Btu heat input) measured or predicted.

(3) The 30-day average NOx emission rate (lb/million Btu heat input) calculated at the end of each steam generating unit operating day from the measured NOx emission rates for the preceding 30 steam generating unit operating days.

(4) Identification of the steam generating unit operating days when the calculated 30-day average NOx emission rates are in excess of the nitrogen oxides emission limit for each HRSG DB (Emission Unit ID#s I-B and II-B). Include the reasons for such excess emissions as well as a description of corrective actions taken.

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken.

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data.

(7) Identification of 'F' factor used for calculations, method of determination, and type of fuel combusted.

(8) Identification of the times when the pollutant concentration (NOx) exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specifications.

(10) Results of CEMS drift tests and quarterly accuracy assessments.

(9 VAC 5-80-110, 9 VAC 5-50-410 Subpart Db, 40 CFR 60 Subpart Db, 40 CFR 60.49b, and Condition 47 of May 15, 2003, Permit)

Auxiliary Boiler Records - 9 VAC 5-50-410 Subpart Dc

j. The permittee shall maintain records of distillate fuel oil supplier certifications for all Numbers 1 and 2 distillate fuel oil burned in the auxiliary boiler (Emission Unit ID# III).
(9 VAC 5-80-110, 9 VAC 5-50-410 Subpart Dc, 40 CFR 60 Subpart Dc, 40 CFR 60.48c, and Condition 47 of May 15, 2003, Permit)

k. The permittee shall maintain records of the amount of each fuel combusted by the auxiliary boiler (Emission Unit ID# III) on a daily basis.
(9 VAC 5-80-110, 9 VAC 5-50-410 Subpart Dc, 40 CFR 60 Subpart Dc, 40 CFR 60.48c, and Condition 47 of May 15, 2003, Permit)

All of the preceding records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-80-110, 9 VAC 5-50-50, 9 VAC 5-50-410 Subparts Db, Dc, and GG, 40 CFR 60 Subparts Db, Dc, and GG, and Condition 47 of May 15, 2003, Permit)

48. **On Site Records -** The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit and to support the reporting requirements of this permit. The content and format of such records shall be arranged with the DEQ, Fredericksburg Office. These records shall include, but are not limited to:

CT or CT/HRSG DB Records

a. Records of pounds/hour emissions of SO_2 for each CT and each CT HRSG/DB (Emission Unit ID#s I-A, I-B and II-A, II-B), calculated hourly. Calculations shall be based on the amount of fuel burned and the sulfur content. The permittee shall maintain supporting data on a daily basis and a sample calculation on an annual basis.

HRSG DB Records

b. Records of each instance where a CT (Emission Unit ID#s I-A and II-A) and its associated HRSG DB (Emission Unit ID#s I-B and II-B) do not burn the same type fuel during periods of normal operation.

Auxiliary Boiler Records

c. Records of each instance when the auxiliary boiler (Emission Unit ID# III) produces steam for the sole purpose of driving a steam turbine to generate electricity.

d. Records of auxiliary boiler (Emission Unit ID# III) opacity measurement obtained by the COMS and by any Method 9 opacity observations. (9 VAC 5-80-110 F)

Diesel Engine Fire Suppression Water Pump Records

e. Records of the amount of Numbers 1 and 2 distillate fuel oil combusted by the diesel engine (Emission Unit ID# DP-1) will be tabulated on a monthly basis. Using DEQ approved emission factors, the permittee shall calculate and record NOx, CO, SO_2, VOC and PM_{10} emissions generated by the diesel engine, on a monthly basis.

Facility Records

f. Records of each replacement or addition of SCR catalyst.

g. The permittee shall calculate and document excess emissions resulting from CT start-up operations that last more than 6 hours.

h. Records at the plant site showing the dimensions of the Numbers 1 and 2 distillate fuel oil storage tank (Emission Unit ID# TK-101) and an analysis showing the capacity of the tank shall be maintained at the plant-site.

i. Records of the quantity of natural gas and Numbers 1 and 2 distillate fuel oil burned in each CT (Emission Unit ID#s I-A and II-A), HRSG DB (Emission Unit ID#s I-B and II-B), and auxiliary boiler (Emission Unit ID# III) on a daily basis. The annual quantity (volume) of natural gas and Numbers 1 and 2 distillate fuel oil burned facility-wide shall be calculated and recorded daily on a 365 day rolling basis.

j. Records of hourly heat input (mmBtu/hr) to each HRSG DB (Emission Unit ID#s I-B and II-B) and the auxiliary boiler (Emission Unit ID# III).

k. Monitoring results of each test to determine sulfur content (grains sulfur/100 dscf natural gas) and the HHV of the natural gas, and the date the test was performed.

l. Records of the numerical results of each natural gas sulfur content test (grains/100 dscf) or the 365 consecutive day rolling average of the natural gas sulfur content, calculated daily. Results of daily 365 consecutive day rolling average of natural gas sulfur content shall be calculated and recorded starting with the first test result that demonstrates the sulfur content of the natural gas is greater than 0.5 grains/100 dscf. The 365 consecutive day rolling average shall be calculated and recorded daily until the annual average drops below 0.5 grains/100 dscf.

m. Date of test, test method used, and test results for HHV and sulfur content of the as-fired Numbers 1 and 2 distillate fuel oil. The permittee shall obtain and maintain certifications of as-fired Numbers 1 and 2 distillate fuel oil sulfur content and HHV as determined by the permittee, a service contractor retained by the permittee, the fuel oil vendor or other DEQ approved agency.

n. Record the 'F' factor or the volume of stack gases used to convert NOx and CO CEMS concentrations to mass emission rates, method of determination, and type of fuel combusted.

o. Records of continuous monitoring system (CEMS and COMS) calibrations and calibration checks, data capture percentages for the CT/HRSG DB CEMS and COMS, data capture percentages for the HRSG DB CEMS, and continuous monitoring system quality assurance checks.

p. For each CT (Emission Unit ID#s I-A and II-A), HRSG DB (Emission Unit ID#s I-B and II-B), and auxiliary boiler (Emission Unit ID# III), maintain daily records of each emission unit's operating mode, as defined in Appendix B of this permit, and records of the number of hours of operation in each operating mode.

All of the preceding records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-80-110, 9 VAC 5-50-50, and Condition 48 of May 15, 2003, Permit)

D. Testing

49. The permitted facility shall be constructed so as to allow for emissions testing at any time using appropriate methods. Upon request from the Department, test ports shall be provided at the appropriate locations.
(9 VAC 5-50-30 and 9 VAC 5-80-110)

50. If testing is conducted in addition to the monitoring specified in this permit, the permittee shall provide the DEQ, Northern Virginia Regional Office (NVRO), Air Compliance Manager (ACM) with two copies of the testing protocol and shall request the ACM's approval of the test protocol at least thirty days prior to the test. The tests shall be conducted and reported and data reduced as set for the in 9 VAC 5-50-30 and 9 VAC 5-60-30, and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410 and 9 VAC 5-60-70. Two copies of the test results shall be submitted to the NVRO, ACM within forty-five days after test completion and shall conform to the test report format specified by the ACM.
(9 VAC 5-80-110 and 9 VAC 5-50-30)

E. Reporting

51. **Continuous Monitoring System (CMS) Excess Emission Report -** The permittee shall furnish written reports to the DEQ, Fredericksburg Office of excess emissions from any process monitored by a continuous monitoring system on a quarterly basis, postmarked no later than the 30th day following the end of the calendar quarter. These reports shall include, but are not limited to the following information:

    a. The magnitude of excess emissions, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions;

    b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the process, the nature and cause of the malfunction (if known), the corrective action taken or preventative measures adopted;

    c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments; and

d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in that report.

(9 VAC 5-80-110, 9 VAC 5-50-50, and Condition 49 of May 15, 2003, Permit)

52. **CEMS and CMS Excess Emission Reports -** The permittee shall furnish written reports to the DEQ, Fredericksburg Office of excess emissions from emission units identified below, on a quarterly basis, postmarked no later than the 30th day following the end of the calendar quarter. These reports shall include, but are not limited to the following information:

CT Excess Emissions Report

a. Report any daily period when the sulfur content of the natural gas or Numbers 1 and 2 distillate fuel oil fired in the CT (Emission Unit ID#s I-A and II-A) exceeds 0.8 percent.
(9 VAC 5-80-110, 9 VAC 5-50-50, 9 VAC 5-50-410 Subpart GG, 40 CFR 60 Subpart GG, 40 CFR 60.334, and Condition 50 of May 15, 2003, Permit)

b. For each month in the quarter, report each period during which an Ice Fog exemption provided in 40 CFR 60.332(f) is in effect. For each ice fog exemption, report the ambient conditions (including temperature and barometric pressure), the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated.
(9 VAC 5-80-110, 9 VAC 5-50-50, 9 VAC 5-50-410 Subpart GG, 40 CFR 60 Subpart GG, 40 CFR 60.334(c)(3), and Condition 50 of May 15, 2003, Permit)

c. For each month in the quarter, report, as required in 40 CFR 60.7(c), each period during which an emergency fuel exemption provided in 40 CFR 60.332(k) is in effect. For each emergency fuel exemption, report the type, reasons, and duration of the firing of the emergency fuel.
(9 VAC 5-80-110, 9 VAC 5-50-50, 9 VAC 5-50-410 Subpart GG, 40 CFR 60 Subpart GG, 40 CFR 60.334(c)(4), and Condition 50 of May 15, 2003, Permit)

CT or CT/HRSG DB Excess Emissions Report

d. For each month in the quarter, report each hour in which a CT or CT/HRSG DB (Emission Unit ID#s I-A, I-B, and II-A, II-B) hourly NOx (as NO_2) permit limit is exceeded. The report shall include the following for each excess emission of NOx: start time, end time, duration, emission units involved, actual NOx emission in ppmdv @ 15% O_2 for CT, actual NOx emission in pounds/10^6 Btu for HRSG DB, average water-to-fuel ratio of the CT (ratio not required provided the CT NOx CEMS required by this permit is maintained in accordance with 40 CFR Part 75 and is fully compliant with 40 CFR 75 and Part 75 data substitution procedures), fuel type, fuel consumption rate, actual weather conditions (temperature and barometric pressure), and CT load.

In accordance with Applicability Determination Index (ADI) Control Number 0200080, item 4, the average hourly water-to-fuel ratio of each CT need not be calculated, recorded or reported if the CT NOx CEMS required by this permit is maintained in accordance with 40 CFR Part 75 and is fully compliant with 40 CFR 75 and Part 75 data substitution procedures.
(9 VAC 5-80-110, 9 VAC 5-50-50, 9 VAC 5-50-410 Subpart GG, 40 CFR 60 Subpart GG, 40 CFR 60.334(c), and Condition 50 of May 15, 2003, Permit)

e. For each month in the quarter, report each day in which a CT or CT/HRSG DB (Emission Unit ID#s I-A, I-B, and II-A, II-B) CO permit limit is exceeded. The report shall include the following for each excess emission of CO: start time, end time, duration, emission units involved, actual CO emissions in ppmdv @ 15% O_2 and lbs CO/hour/unit, fuel type, fuel consumption rate, and CT load.
(9 VAC 5-80-110, 9 VAC 5-50-50, and Condition 50 of May 15, 2003, Permit)

f. For each month in the quarter, report each day in which a CT or CT/HRSG DB (Emission Unit ID#s I-A, I-B, and II-A, II-B) opacity limit is exceeded, including periods of startup, shutdown, or malfunction. The report shall include the following for each excess emission of opacity: start time, duration, emission units involved, actual opacity reading(s), fuel type and consumption rate, CT load, and corrective action taken. Excess opacity emissions for the CT and CT/HRSG DBs (Emission Unit ID#s I-A, I-B, and II-A, II-B) are defined as all 6-minute periods during which the average opacity exceeds the opacity standard. The quarterly report shall include a monitoring system downtime report and/or summaries in accordance with 40 CFR 60.7 (c) and (d), and 40 CFR 75.
(9 VAC 5-80-110, 9 VAC 5-50-50, 9 VAC 5-50-410 Subpart Db, 40 CFR 60 Subpart Db, 40 CFR 60.49b, and Condition 50 of May 15, 2003, Permit)

g. HRSG DB (Emission Unit ID#s I-B and II-B) - For each day in the quarter, report any excess emissions of NOx generated by each HRSG DB

(Emission Unit ID#s I-B and II-B). Excess emissions are defined as each calculated 30-day rolling average NOx emission rate which exceeds the NOx emission limit contained in this permit for HRSG DBs (Emission Unit ID#s I-B and II-B).
(9 VAC 5-80-110, 9 VAC 5-50-50, 9 VAC 5-50-410 Subpart Db, 40 CFR 60 Subpart Db, 40 CFR 60.49b, and Condition 50 of May 15, 2003, Permit)

53. **Quarterly Report - 9 VAC 5-50-410 Subparts Db, Dc, and GG -** The permittee shall submit reports to the DEQ, Fredericksburg Office, within 30 days after the end of each quarterly period. Each quarterly report shall include the dates covered in the report and shall include the following:

HRSG DB Quarterly Reporting

a. The annual capacity factor for each fuel burned in each HRSG DB (Emission Unit ID#s I-B and II-B), reported for each month of the calendar quarter. The annual capacity factor is determined on a rolling 12-month basis.
(9 VAC 5-80-110, 9 VAC 5-50-410 Subpart Db, 40 CFR 60 Subpart Db, 40 CFR 60.49b, and Condition 51 of May 15, 2003, Permit)

b. The daily records maintained for each HRSG DB (Emission Unit ID#s I-B and II-B) steam generating unit operating day, as contained in the record keeping section of this permit.
(9 VAC 5-80-110, 9 VAC 5-50-410 Subpart Db, 40 CFR 60 Subpart Db, 40 CFR 60.49b (i), and Condition 51 of May 15, 2003, Permit)

HRSG DB and Auxiliary Boiler Quarterly Report

c. If Numbers 1 and 2 distillate oil was received during the calendar quarter, the quarterly report shall include a certified signed statement from the permittee that states the fuel supplier certifications (maintained at the facility) represent all of the distillate oil burned in the HRSG DBs (Emission Unit ID#s I-B and II-B) and auxiliary boiler (Emission Unit ID# III) or represent all of the distillate oil received at this facility during the quarter. The certified statement shall indicate whether all the Numbers 1 and 2 distillate fuel oil burned at this facility or in the HRSG DBs (Emission Unit ID#s I-B and II-B) and the auxiliary boiler (Emission Unit ID# III) meets the definition of distillate oil as defined 40 CFR 60 Subparts Db and Dc. The statement shall include the name of the Numbers 1 and 2 distillate fuel oil supplier(s) and the test method used to determine sulfur content.
(9 VAC 5-80-110, 9 VAC 5-50-410 Subparts Db and Dc, 40 CFR 60 Subparts Db and Dc, 40 CFR 60.49b, and 40 CFR 60.48c, and Condition 51 of May 15, 2003, Permit)

d. If no shipments of Numbers 1 and 2 distillate fuel oil were received during the calendar quarter, the quarterly report shall include a statement that no distillate oil was received during the calendar quarter.
(9 VAC 5-80-110, 9 VAC 5-50-410 Subpart Db and Dc, 40 CFR 60 Subpart Db and Dc, 40 CFR 60.49b, and 40 CFR 60.48c and Condition 51 of May 15, 2003, Permit)

54. **Quarterly Report** - The permittee shall submit reports to the DEQ, Fredericksburg Office, within 30 days after the end of each quarterly period. Each quarterly report shall include the dates covered in the report and shall include the following:

a. For each month in the quarter, report each hour in which the actual heat input sum of the HRSG DBs (Emission Unit ID#s I-B and II-B) and the auxiliary boiler (Emission Unit ID III) exceeds 249 million Btu/hour. The quarterly report shall include the following for each occurrence: the type of fuel consumed by each emission unit, the actual heat input rate and actual rate of fuel consumption (actual volume fuel consumed per hour) for each emissions unit, and the HHV of the fuel (Btu per volume fuel).

b. For each month in the quarter, report the annual facility-wide emissions of NOx (as NO_2), CO, SO_2, VOC and PM_{10} by calculating a rolling sum of facility-wide emissions over each consecutive 12 month period.

c. For each month in the quarter, report each day within the quarter when the rolling 365 consecutive day sum of Numbers 1 and 2 distillate fuel oil burned in the diesel driven fire suppression water pump (Emission Unit ID# DP-1) exceeds the permitted annual fuel throughput limitation.

d. For each month in the quarter, report each day that the rolling 365 consecutive day sum of facility-wide NOx, SO_2, CO, VOC or PM_{10} emissions exceeds the respective facility-wide annual permit limit. Include the pollutant name and the calculated 365 day sum of emissions for each pollutant that exceeds its annual permit emission limit. For each day reported, at minimum, include the pollutant name, the pollutant's 365 consecutive day sum of facility-wide emissions, and identify any data substitution.

For the purposes of this condition, the permittee shall, at a minimum, include daily emissions from each CT and CT/HRSG DB (Emission Unit ID#s I-A, I-B and II-A, II-B), daily emissions from the auxiliary boiler (Emission Unit ID# III), and monthly emissions from the diesel engine driven emergency water pump (Emission Unit ID# DP-1) in the calculation of facility-wide annual emissions.

Monthly emissions from the diesel engine (Emission Unit ID# DP-1) driven fire suppression water pump generated during month "X" shall be included in the annual rolling 365 consecutive day emission summation on the last day of month "X".

For the purpose of calculating annual facility-wide NOx and CO emissions, hourly NOx and CO CEMS data from the CT and CT/HRSG DB (Emission Units I-A, I-B and II-A, II-B) shall be included in the rolling annual emissions calculation. When valid NOx and CO CEMS data is not available, the default emission rates contained in Appendix B of this permit shall be substituted for the missing data.

For the purpose of calculating annual facility-wide SO_2 emissions, the sulfur content of the fuel and the quantity of fuel burned in each emission unit shall be used to calculate daily SO_2 emissions. The calculated daily emissions of SO_2 shall be summed over each 365 consecutive day period to determine annual emissions.

For the purpose of calculating annual facility-wide VOC and PM_{10} emissions, the permittee shall calculate daily emissions for each emissions unit using emission factors and process parameters approved in advance by the DEQ. The calculated daily emissions of VOC and PM_{10} shall be summed over each 365 consecutive day period to determine annual emissions.

For the purpose of calculating annual emission of NOx, CO, VOC, and PM_{10} generated by the auxiliary boiler (Emission Unit ID# III) the permittee shall use the default emission factors contained in Appendix B of this permit for the boiler. For the purpose of calculating annual emission of NOx and CO generated by the diesel engine driven emergency water pump (Emission Unit ID# DP-1), the permittee shall calculate monthly emissions by using emission factors and process parameters approved in advance by the DEQ.

e. For each month of the quarter, report each occasion the auxiliary boiler (Emission Unit ID# III) produces steam for use in a steam turbine to generate electricity.

f. For each month in the quarter, report each day in which the auxiliary boiler (Emission Unit ID#s III) opacity limit is exceeded, including periods of startup, shutdown, or malfunction. The report shall include the following for each excess emission of opacity: start time, duration, emission units involved, actual opacity reading(s), fuel type and consumption rate, and corrective action taken. Excess opacity emissions for the auxiliary boiler (Emission Unit ID#s III) are defined as all 6-minute periods during which

the average opacity exceeds the opacity standard of this permit. The quarterly report shall include a monitoring system downtime report and/or summaries as described in 40 CFR 60.7 (c) and (d).
(9 VAC 5-80-110 E and F, 9 VAC 5-50-50)

g. For each month of the quarter, report each instance where a CT (Emission Unit ID#s I-A and II-A) and its associated HRSG DB (Emission Unit ID#s I-B and II-B) do not burn the same type fuel.

h. For each month of the quarter, report each day when the calculated hourly SO_2 emission rate exceeds the SO_2 emission limit for each CT or CT/HRSG DB (Emission Unit ID#s I-A, I-B and II-A, II-B). The report shall include the calculated emission rate, type of fuel burned, and the time and duration of the exceedance.

Facility Quarterly Reporting

i. For each quarter, submit a report on the SCR system operations. The report shall include statements of each replacement or addition of SCR catalyst. Details are to be arranged with the DEQ Fredericksburg Office.

j. For each month in the quarter, report all hourly excess emissions and all annual excess emissions (as calculated on a daily basis) for the following pollutants: NOx, CO, SO_2, VOC and PM_{10}. Excess emissions resulting from CT start-up operations lasting less than 6 hours may be identified as start-up excess emissions. All excess emissions shall be included in the rolling 365 consecutive day facility-wide emissions summation.

k. For each day in the quarter, when the annual rolling 365 consecutive day sum of natural gas or Numbers 1 and 2 distillate fuel oil burned at the facility exceeds an annual facility-wide fuel throughput limit, report the date and annual facility-wide quantity of fuel burned.

l. For each month in the quarter, report each day when natural gas is burned and the sulfur content of the gas exceeds 20 grains/100 dscf. For each month in the quarter, report each day in which natural gas is burned and the annual weighted average sulfur content of the natural gas exceeds 0.5 grains of sulfur/100 dscf.

For each month in the quarter, report each day when Numbers 1 or 2 distillate fuel oil is burned and the sulfur content of the oil exceeds 0.05% by weight.

m. For each month in the quarter, report each occasion when the measured HHV of the natural gas is less than 967 Btu/scf. Records shall include the test date, measured HHV, fuel sulfur content, and the quantity of natural gas burned and the hours of emission unit operation since the natural gas was previously tested for its HHV.

n. For each month in the quarter, report each occasion when the measured HHV of the distillate fuel oil is less than 132,000 Btu/gallon fuel. Records shall include the test date, measured HHV, fuel sulfur content, and the quantity of distillate oil burned and the hours of emission unit operation since the distillate oil was previously tested for its HHV.

o. With regard to visible emissions and opacity monitoring, the permittee shall report all excess opacity and the percentage of operating hours for which opacity monitoring data have not been obtained. If no excess opacity occurred or no opacity monitoring data were obtained for all operating hours during the reporting period, the quarterly report shall contain a statement as such.

(9 VAC 5-80-110, 9 VAC 5-50-50, and Condition 52 of May 15, 2003, Permit)

55. **Report Distribution -** The permittee shall submit one copy of excess emission reports and one copy of all quarterly reports to the DEQ Fredericksburg Office within 30 days after the end of each calendar quarter. The permittee shall send one copy of all excess emission reports and one copy of all Quarterly Reports for 9 VAC 5-50-410 Subparts Db, Dc, and GG to the Environmental Protection Agency (EPA) within 30 days after the end of each calendar quarter. Copies of reports for the EPA shall be sent to:

Associate Director
Office of Air Enforcement (3AP10)
U. S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

(9 VAC 5-80-110, 9 VAC 5-50-50, 9 VAC 5-50-410 Subparts Db, Dc and GG, 40 CFR 60 Subparts Db, Dc, and GG, 40 CFR 60.48c and Condition 53 of May 15, 2003, Permit)

IV. Insignificant Emission Units

The following emission units at the facility are identified in the application as insignificant emission units under 9 VAC 5-80-720:

Emission Unit No.	Emission Unit Description	Citation	Pollutant(s) Emitted (9 VAC 5-80-720 B)	Rated Capacity (9 VAC 5-80-720 C)
DP-1	Patterson Pump Emergency Fire Pump. Pump driven by a Caterpillar Model 3306 diesel fired internal combustion engine.	9 VAC 5-80-720.C	-	231 horsepower, 11.9 gallons/hour @ 1750 rpm. Operates less than 500 hours/year.
TK-101	Number 1 and 2 distillate fuel oil storage tank	9 VAC 5-80-720.B	VOC emissions less than 1 ton/yr.	-
CTG #1 and 2	Combustion Turbine Generator (CTG) Lube Oil Sumps	9 VAC 5-80-720.B	VOC emissions less than 1 ton/yr.	-
STG #1 and 2	Steam Turbine Generator (STG) Lube Oil Sumps	9 VAC 5-80-720.B	VOC emissions less than 1 ton/yr.	
STG #1 and 2	Hydraulic Oil Tanks	9 VAC 5-80-720.C	-	Less than 1000 gallons each.
O/W - 103 A/B/C	Stormwater (drain tank) Oil/Water Separator	9 VAC 5-80-720.B	VOC emissions less than 1 ton/yr.	-
EV and CR	Evaporator and Crystalizer	9 VAC 5-80-720.B.5	Chloroform Diethyl phthalate Ethylbenzene Methylene Chloride Toluene Xylenes	-
-	Sulfuric Acid Tank for boiler water treatment operation	9 VAC 5-80-720.A.43	-	-
-	Sodium Hydroxide for boiler water treatment operation	9 VAC 5-80-720.A.43	-	-

These emission units are presumed to be in compliance with all requirements of the federal Clean Air Act as may apply. Based on this presumption, no monitoring, recordkeeping, or reporting shall be required for these emission units in accordance with 9 VAC 5-80-110.

V. Permit Shield & Inapplicable Requirements

Compliance with the provisions of this permit shall be deemed compliance with all applicable requirements in effect as of the permit issuance date as identified in this permit. This permit shield covers only those applicable requirements covered by terms and conditions in this permit and the following requirements which have been specifically identified as being not applicable to this permitted facility:

Citation	Title of Citation	Description of Applicability
None Cited in Application		

Nothing in this permit shield shall alter the provisions of §303 of the federal Clean Air Act, including the authority of the administrator under that section, the liability of the owner for any violation of applicable requirements prior to or at the time of permit issuance, or the ability to obtain information by the administrator pursuant to §114 of the federal Clean Air Act, (ii) the Board pursuant to §10.1-1314 or §10.1-1315 of the Virginia Air Pollution Control Law or (iii) the Department pursuant to §10.1-1307.3 of the Virginia Air Pollution Control Law.
(9 VAC 5-80-140)

VI. General Conditions

A. Federal Enforceability

All terms and conditions in this permit are enforceable by the administrator and citizens under the federal Clean Air Act, except those conditions that have been designated as only state-enforceable.
(9 VAC 5-80-110 N)

B. Permit Expiration

This permit has a fixed term of five years. The expiration date shall be the date five years from the date of issuance. Unless a timely and complete renewal application consistent, with 9 VAC 5-80-80, has been submitted, to the DEQ, Fredericksburg Satellite Office (Department), by the owner, the right of the facility to operate shall be terminated upon permit expiration.

1. The owner shall submit an application for renewal at least six months but no earlier than eighteen months prior to the date of permit expiration.

2. If an applicant submits a timely and complete application for an initial permit or renewal under this section, the failure of the source to have a permit or the operation of the source without a permit shall not be a violation of Article 1, Part II of 9 VAC 5 Chapter 80, until the Board takes final action on the application under 9 VAC 5-80-150.

3. No source shall operate after the time that it is required to submit a timely and complete application under subsections C and D of 9 VAC 5-80-80 for a renewal permit, except in compliance with a permit issued under Article 1, Part II of 9 VAC 5 Chapter 80.

4. If an applicant submits a timely and complete application under section 9 VAC 5-80-80 for a permit renewal but the Board fails to issue or deny the renewal permit before the end of the term of the previous permit, (i) the previous permit shall not expire until the renewal permit has been issued or denied and (ii) all the terms and conditions of the previous permit, including any permit shield granted pursuant to 9 VAC 5-80-140, shall remain in effect from the date the application is determined to be complete until the renewal permit is issued or denied.

5. The protection under subsections F 1 and F 5 (ii) of section 9 VAC 5-80-80 F shall cease to apply if, subsequent to the completeness determination made pursuant section 9 VAC 5-80-80 D, the applicant fails to submit by the deadline specified in writing by the Board any additional information identified as being needed to process the application.

(9 VAC 5-80-80 B, C and F, 9 VAC 5-80-110 D and 9 VAC 5-80-170 B)

C. Recordkeeping and Reporting

1. All records of monitoring information maintained to demonstrate compliance with the terms and conditions of this permit shall contain, where applicable, the following:

    a. The date, place as defined in the permit, and time of sampling or measurements.

    b. The date(s) analyses were performed.

    c. The company or entity that performed the analyses.

    d. The analytical techniques or methods used.

e. The results of such analyses.

f. The operating conditions existing at the time of sampling or measurement.

(9 VAC 5-80-110 F)

2. Records of all monitoring data and support information shall be retained for at least five years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.
(9 VAC 5-80-110 F)

3. The permittee shall submit the results of monitoring contained in any applicable requirement to DEQ no later than **March 1** and **September 1** of each calendar year. This report must be signed by a responsible official, consistent with 9 VAC 5-80-80 G, and shall include:

a. The time period included in the report. The time periods to be addressed are January 1 to June 30 and July 1 to December 31.

b. All deviations from permit requirements. For purposes of this permit, deviations include, but are not limited to:

(1) Exceedance of emissions limitations or operational restrictions;

(2) Excursions from control device operating parameter requirements, as documented by continuous emission monitoring, periodic monitoring, or compliance assurance monitoring which indicates an exceedance of emission limitations or operational restrictions; or,

(3) Failure to meet monitoring, recordkeeping, or reporting requirements contained in this permit.

c. If there were no deviations from permit conditions during the time period, the permittee shall include a statement in the report that “no deviations from permit requirements occurred during this semi-annual reporting period.”

(9 VAC 5-80-110 F)

D. Annual Compliance Certification

Exclusive of any reporting required to assure compliance with the terms and conditions of this permit or as part of a schedule of compliance contained in this permit, the permittee shall submit to EPA and DEQ no later than **March 1** each calendar year a certification of compliance with all terms and conditions of this permit including emission limitation standards or work practices. The compliance certification shall comply with such additional requirements that may be specified pursuant to §114(a)(3) and §504(b) of the federal Clean Air Act. This certification shall be signed by a responsible official, consistent with 9 VAC 5-80-80 G, and shall include:

1. The time period included in the certification. The time period to be addressed is January 1 to December 31.

2. The identification of each term or condition of the permit that is the basis of the certification.

3. The compliance status.

4. Whether compliance was continuous or intermittent, and if not continuous, documentation of each incident of non-compliance.

5. Consistent with subsection 9 VAC 5-80-110 E, the method or methods used for determining the compliance status of the source at the time of certification and over the reporting period.

6. Such other facts as the permit may require to determine the compliance status of the source.

One copy of the annual compliance certification shall be sent to EPA at the following address:

Clean Air Act Title V Compliance Certification (3AP00)
U. S. Environmental Protection Agency, Region III
1650 Arch Street
Philadelphia, PA 19103-2029.

(9 VAC 5-80-110 K.5)

E. Permit Deviation Reporting

The permittee shall notify the DEQ, Fredericksburg Satellite Office (DEQ FSO) within four daytime business hours, after discovery of any deviations from permit requirements which may cause excess emissions for more than one hour, including those attributable to upset conditions as may be defined in this permit. In addition, within fourteen days of the discovery, the permittee shall provide a written statement explaining the problem, any corrective actions or preventative measures taken, and the estimated duration of the permit deviation. Owners subject to the requirements of 9 VAC 5-40-50 C and 9 VAC 5-50-50 C are not

required to provide the written statement prescribed in this paragraph for facilities subject to the monitoring requirements of 9 VAC 5-40-40 and 9 VAC 5-50-40. The occurrence should also be reported in the next semi-annual compliance monitoring report pursuant to General Condition C.3. of this permit.
(9 VAC 5-80-110 F.2 and 9 VAC 5-80-250)

F. Failure/Malfunction Reporting

In the event that any affected facility or related air pollution control equipment fails or malfunctions in such a manner that may cause excess emissions for more than one hour, the owner shall, as soon as practicable but no later than four daytime business hours after the malfunction is discovered, notify the DEQ, FSO by facsimile transmission, telephone or telegraph of such failure or malfunction and shall within two weeks provide a written statement giving all pertinent facts, including the estimated duration of the breakdown. Owners subject to the requirements of 9 VAC 5-40-50 C and 9 VAC 5-50-50 C are not required to provide the written statement prescribed in this paragraph for facilities subject to the monitoring requirements of 9 VAC 5-40-40 and 9 VAC 5-50-40. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the owner shall notify the DEQ, FSO.

1. The emission units that have continuous monitors subject to 9 VAC 5-40-50 C and 9 VAC 5-50-50 C are not subject to the two week written notification.

2. The emission units subject to the reporting and the procedure requirements of 9 VAC 5-50-50 C are listed below:

   a. NOx CEMS measurements for each CT/HRSG DB (Emission Unit ID#s I-A, I-B, II-A, and II-B); and
   b. CO CEMS measurements for each CT/HRSG DB (Emission Unit ID#s I-A, I-B, II-A, and II-B).

3. Each owner required to install a continuous monitoring system subject to 9 VAC 5-40-41 or 9 VAC 5-50-410 shall submit a written report of excess emissions (as defined in the applicable emission standard) to the board for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter and shall include the following information:

   a. The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h) or 9 VAC 5-40-41 B 6, any conversion factors used, and the date and time of commencement and completion of each period of excess emissions;

   b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the source. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted;

c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments; and

d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in the report.

4. All emission units not subject to 9 VAC 5-40-50 C and 9 VAC 5-50-50 C must make written reports within 14 days of the malfunction occurrence.

(9 VAC 5-20-180 C and 9 VAC 5-50-50)

G. Severability

The terms of this permit are severable. If any condition, requirement or portion of the permit is held invalid or inapplicable under any circumstance, such invalidity or inapplicability shall not affect or impair the remaining conditions, requirements, or portions of the permit.
(9 VAC 5-80-110 G.1)

H. Duty to Comply

The permittee shall comply with all terms and conditions of this permit. Any permit noncompliance constitutes a violation of the federal Clean Air Act or the Virginia Air Pollution Control Law or both and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or, for denial of a permit renewal application.
(9 VAC 5-80-110 G.2)

I. Need to Halt or Reduce Activity not a Defense

It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.
(9 VAC 5-80-110 G.3)

J. Permit Action for Cause

A physical change in or change in the method of operation of this stationary source may be subject to permitting under State Regulations 9 VAC 5-80-50, 9 VAC 5-80-1100, 9 VAC 5-80-1790, or 9 VAC 5-80-2000 and may require a permit modification and/or revisions except as may be authorized in any approved alternative operating scenarios.
(9 VAC 5-80-190 and 9 VAC 5-80-260)

K. Property Rights

The permit does not convey any property rights of any sort, or any exclusive privilege.
(9 VAC 5-80-110 G.5)

L. Duty to Submit Information

1. The permittee shall furnish to the Board, within a reasonable time, any information that the Board may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Board copies of records required to be kept by the permit and, for information claimed to be confidential, the permittee shall furnish such records to the Board along with a claim of confidentiality.
(9 VAC 5-80-110 G.6)

2. Any document (including reports) required in a permit condition to be submitted to the Board shall contain a certification by a responsible official that meets the requirements of 9 VAC 5-80-80 G.
(9 VAC 5-80-110 K.1)

M. Duty to Pay Permit Fees

The owner of any source for which a permit under 9 VAC 5-80-50 through 9 VAC 5-80-300 was issued shall pay permit fees consistent with the requirements of 9 VAC 5-80-310 through 9 VAC 5-80-350. The actual emissions covered by the permit program fees for the preceding year shall be calculated by the owner and submitted to the Department by <u>April 15</u> of each year. The calculations and final amount of emissions are subject to verification and final determination by the Department.
(9 VAC 5-80-110 H and 9 VAC 5-80-340 C)

N. Fugitive Dust Emission Standards

During the operation of a stationary source or any other building, structure, facility, or installation, no owner or other person shall cause or permit any materials or property to be handled, transported, stored, used, constructed, altered, repaired, or demolished without taking reasonable precautions to prevent particulate matter from becoming airborne. Such reasonable precautions may include, but are not limited to, the following:

1. Use, where possible, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads, or the clearing of land;

2. Application of asphalt, water, or suitable chemicals on dirt roads, materials stockpiles, and other surfaces which may create airborne dust; the paving of roadways and the maintaining of them in a clean condition;

3. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty material. Adequate containment methods shall be employed during sandblasting or other similar operations;

4. Open equipment for conveying or transporting material likely to create objectionable air pollution when airborne shall be covered or treated in an equally effective manner at all times when in motion; and,

5. The prompt removal of spilled or tracked dirt or other materials from paved streets and of dried sediments resulting from soil erosion.

(9 VAC 5-50-90)

O. Startup, Shutdown, and Malfunction

At all times, including periods of startup, shutdown, soot blowing, and malfunction, owners shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Board, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
(9 VAC 5-50-20 E)

P. Alternative Operating Scenarios

Contemporaneously with making a change between reasonably anticipated operating scenarios identified in this permit, the permittee shall record in a log at the permitted facility a record of the scenario under which it is operating. The permit shield described in 9 VAC 5-80-140 shall extend to all terms and conditions under each such operating scenario. The terms and conditions of each such alternative scenario shall meet all applicable requirements including the requirements of 9 VAC 5 Chapter 80, Article 1.
(9 VAC 5-80-110 J)

Q. Inspection and Entry Requirements

The permittee shall allow DEQ, upon presentation of credentials and other documents as may be required by law, to perform the following:

1. Enter upon the premises where the source is located or emissions-related activity is conducted, or where records must be kept under the terms and conditions of the permit.

2. Have access to and copy, at reasonable times, any records that must be kept under the terms and conditions of the permit.

3. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit.

4. Sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

(9 VAC 5-80-110 K.2)

R. Reopening For Cause

The permit shall be reopened by the Board if additional federal requirements become applicable to a major source with a remaining permit term of three years or more. Such reopening shall be completed no later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended pursuant to 9 VAC 5-80-80 F.

1. The permit shall be reopened if the Board or the administrator determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.

2. The permit shall be reopened if the administrator or the Board determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

3. The permit shall not be reopened by the Board if additional applicable state requirements become applicable to a major source prior to the expiration date established under 9 VAC 5-80-110 D.

(9 VAC 5-80-110 L)

S. Permit Availability

Within five days after receipt of the issued permit, the permittee shall maintain the permit on the premises for which the permit has been issued and shall make the permit immediately available to DEQ upon request.
(9 VAC 5-80-150 E)

T. Transfer of Permits

1. No person shall transfer a permit from one location to another, unless authorized under 9 VAC 5-80-130, or from one piece of equipment to another. (9 VAC 5-80-160)

2. In the case of a transfer of ownership of a stationary source, the new owner shall comply with any current permit issued to the previous owner. The new owner shall notify the Board of the change in ownership within 30 days of the transfer and shall comply with the requirements of 9 VAC 5-80-200. (9 VAC 5-80-160)

3. In the case of a name change of a stationary source, the owner shall comply with any current permit issued under the previous source name. The owner shall notify the Board of the change in source name within 30 days of the name change and shall comply with the requirements of 9 VAC 5-80-200. (9 VAC 5-80-160)

U. Malfunction as an Affirmative Defense

1. A malfunction constitutes an affirmative defense to an action brought for noncompliance with technology-based emission limitations if the requirements of paragraph 2 of this condition are met.

2. The affirmative defense of malfunction shall be demonstrated by the permittee through properly signed, contemporaneous operating logs, or other relevant evidence that show the following:

    a. A malfunction occurred and the permittee can identify the cause or causes of the malfunction.

    b. The permitted facility was at the time being properly operated.

    c. During the period of the malfunction the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit.

    d. The permittee notified the board of the malfunction within two working days following the time when the emission limitations were exceeded due to the malfunction. This notification shall include a description of the malfunction, any steps taken to mitigate emissions, and corrective actions taken. The notification may be delivered either orally or in writing. The notification may be delivered by electronic mail, facsimile transmission, telephone, or any other method that allows the permittee to comply with the deadline. This notification fulfills the requirements of 9 VAC 5-80-110 F 2 b to report promptly deviations from permit requirements. This notification does not release the permittee from the malfunction reporting requirement under 9 VAC 5-20-180 C.

3. In any enforcement proceeding, the permittee seeking to establish the occurrence of a malfunction shall have the burden of proof.

4. The provisions of this section are in addition to any malfunction, emergency or upset provision contained in any applicable requirement.

(9 VAC 5-80-250)

V. Permit Revocation or Termination for Cause

A permit may be revoked or terminated prior to its expiration date if the owner knowingly makes material misstatements in the permit application or any amendments thereto or if the permittee violates, fails, neglects or refuses to comply with the terms or conditions of the permit, any applicable requirements, or the applicable provisions of 9 VAC 5 Chapter 80 Article 1. The Board may suspend, under such conditions and for such period of time as the Board may prescribe, any permit for any of the grounds for revocation or termination or for any other violations of these regulations.
(9 VAC 5-80-190 C and 9 VAC 5-80-260)

W. Duty to Supplement or Correct Application

Any applicant who fails to submit any relevant facts or who has submitted incorrect information in a permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrections. An applicant shall also provide additional information as necessary to address any requirements that become applicable to the source after the date a complete application was filed but prior to release of a draft permit.
(9 VAC 5-80-80 E)

X. Stratospheric Ozone Protection

If the permittee handles or emits one or more Class I or II substances subject to a standard promulgated under or established by Title VI (Stratospheric Ozone Protection) of the federal Clean Air Act, the permittee shall comply with all applicable sections of 40 CFR Part 82, Subparts A to F.
(40 CFR Part 82, Subparts A-F)

Y. Asbestos Demolition and Renovation Requirements

The permittee shall comply with the requirements of National Emissions Statements for Hazardous Air Pollutants (40 CFR 61) Subpart M, National Emission Standards for Asbestos as it applies to the following: Standards for Demolition and Renovation (40 CFR 61.145), Standards for Insulating Materials (40 CFR 61.148), and Standards for Waste Disposal (40 CFR 61.150).
(9 VAC 5-60-70 and 9 VAC 5-80-110 A.1)

Z. Accidental Release Prevention

If the permittee has more, or will have more than a threshold quantity of a regulated substance in a process, as determined by 40 CFR 68.115, the permittee shall comply with the requirements of 40 CFR Part 68.
(40 CFR Part 68)

AA. Changes to Permits for Emissions Trading

No permit revision shall be required under any federally approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this permit.
(9 VAC 5-80-110 I)

BB. Emissions Trading

Where the trading of emissions increases and decreases within the permitted facility is to occur within the context of this permit and to the extent that the regulations provide for trading such increases and decreases without a case-by-case approval of each emissions trade:

1. All terms and conditions required under 9 VAC 5-80-110, except subsection N, shall be included to determine compliance.

2. The permit shield described in 9 VAC 5-80-140 shall extend to all terms and conditions that allow such increases and decreases in emissions.

3. The owner shall meet all applicable requirements including the requirements of 9 VAC 5-80-50 through 9 VAC 5-80-300.

(9 VAC 5-80-110 I)

CC. Notification for Control Equipment Maintenance

The permittee shall furnish notification to the DEQ, Fredericksburg Office of the intention to shut down or bypass, or both, air pollution control equipment for necessary scheduled maintenance, which results in excess emissions for more than one hour, at least 24 hours prior to the shutdown. The notification shall include, but is not limited to, the following information:

a. Identification of the air pollution control equipment to be taken out of service, as well as its location, and registration number;

b. The expected length of time that the air pollution control equipment will be out of service;

c. The nature and quantity of emissions of air pollutants likely to occur during the shutdown period;

d. Measures that will be taken to minimize the length of the shutdown or to negate the effect of the outage.

DD. Maintenance/Operating Procedures

The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to air pollution control equipment, monitoring devices, and process equipment which affect such emissions:

a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.

b. Maintain an inventory of spare parts.

c. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.

d. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

e. Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.

(9 VAC 5-80-110, 9 VAC 5-50-20 E and Condition 60 of May 15, 2003, Permit)

VII. Appendices

Appendix A

DEFINITION OF COMBUSTION TURBINE START-UP AND TRANSIENT CONDITIONS

Start-Up Conditions

(1) **Normal Start-Up:** Start-up begins when flame is detected. Start-up ends one hour after ammonia injection begins. The start-up period shall not exceed six hours. For situations where malfunctions occur during start-up, the six hours will be exceeded and excess emissions that occur after six hours will be considered exceedances.

(2) **Full Speed, No Load:** The start-up definition shall include full speed, no load testing which is usually conducted weekly for reliability purposes. Full speed, no load testing commences when flame is detected and is distinguished from a normal start-up by the fact that the combustion turbine output (MW) is zero. Full speed, no load is completed at flameout. Full speed, no load start-ups occur for less than sixty minutes in duration.

Transient Conditions (occurs sixty minutes or less in duration)

(1) **Shutdown:** Begins when either the operator initiates a STOP command or if the combustion turbine load has decreased below 85 percent of rated output and within thirty minutes of a STOP command has been initiated. In both cases, the turbine will continue to decrease load until flameout.

(2) **Fuel Switch:** Lower load below 50 MW range, change fuel and raise load again. Verification by records indicating both natural gas and distillate fuel oil flow within sixty minutes of each other.

(3) **Power Augmentation:** Lower load/increase load to reset control logic and enter pre-mix mode. Verification by records indicating both water and natural gas flow.

Appendix B

NOx, SO_2, and CO Data Substitution Emission Factors and VOC and PM_{10} Emission Factors For Use In Annual Facility-wide Emission Calculations

Operating Mode Symbol	Emission Rate (lbs/hr)	Operating Mode Description
CT_{FO}	53 lb SO_2 /hr 43.5 lb CO/hr 52 lb NOx (as NO_2)/hr 10 lb PM10/hr 9.5 lb VOC/hr	Operating hours firing distillate fuel oil in the CT (Emission Unit ID#s I-A and II-A), while no duct burner supplementary firing is used
CT_{FO} plus $HRSG/SFL_{FO}$	60 lb SO_2 /hr 58.5 lb CO/hr 58 lb NOx (as NO_2)/hr 12 lb PM10/hr 17.5 lb VOC/hr	Operating hours firing distillate fuel oil while HRSG duct burner (Emission Unit ID#s I-B and II-B) is supplementary firing low (SFL) at or less than 124.9 MMBtu/hr.
CT_{FO} plus $HRSG/SFH_{FO}$	62 lb SO_2 /hr 63.5 lb CO/hr 60 lb NOx (as NO_2)/hr 13 lb PM10/hr 19.5 lb VOC/hr	operating hours firing distillate fuel oil while HRSG duct burner is supplementary firing high (SFH) at 125.0 through 166.6 MMBtu/hr.
AB_{FO}	1.1 lb SO_2 /hr 1.8 lb CO/hr 3.7 lb NOx (as NO_2)/hr 0.66 lb PM10/hr 0.55 lb VOC/hr	operating hours firing distillate fuel oil in the auxiliary boiler (Emission Unit ID# III).
ST CT_{FO}	53 lb SO_2 /hr 208 lb CO/hr 259 lb NOx (as NO_2)/hr 47.8 lb PM10/hr 45.4 lb VOC/hr	CT operating hours firing distillate fuel oil during start-up. Appendix A contains the definition of start-up.
TR CT_{FO}	53 lb SO_2 /hr 171 lb CO/hr 86 lb NOx (as NO_2)/hr 39.3 lb PM10/hr 37.3 lb VOC/hr	CT operating hours firing distillate fuel oil during transient operations (shutdown, fuel switching, or power augmentation). Appendix A contains the definitions of transient operations.
FSNL CT_{FO}	53 lb SO_2 /hr 282 lb CO/hr 31.5 lb NOx (as NO_2)/hr 64.8 lb PM10/hr 61.6 lb VOC/hr	CT operating hours firing distillate fuel oil during full speed/no load (FSNL). Appendix A contains the definition of FSNL.
CT_{NG}	2.1 lb SO_2 /hr 33 lb CO/hr 39.5 lb NOx (as NO_2)/hr 5 lb PM10/hr	operating hours firing natural gas in the CT, while no duct burner supplementary firing is used.

	10.25 lb VOC/hr	
CT_{NG} plus HRSG/SFL_{NG}	2.2 lb SO_2 /hr 48 lb CO/hr 44.25 lb NOx (as NO_2)/hr 7 lb PM10/hr 18.25 lb VOC/hr	operating hours firing natural gas while the HRSG duct burner is supplementary firing low at or less than 124.9 MMBtu/hr
CT_{NG} plus HRSG/SFH_{NG}	2.3 lb SO_2 /hr 54 lb CO/hr 45.5 lb NOx (as NO_2)/hr 8 lb PM10/hr 21.25 lb VOC/hr	operating hours firing natural gas while the HRSG duct burner is supplementary firing high at 125.0 through 174.7 MMBtu/hr.
AB_{NG}	1.8 lb CO/hr 2.4 lb NOx (as NO_2)/hr 0.11 lb PM10/hr 0.40 lb VOC/hr	operating hours firing natural gas in the auxiliary boiler.
ST CT_{NG}	2.1 lb SO_2 /hr 461 lb CO/hr 88 lb NOx (as NO_2)/hr 69.8 lb PM10/hr 143.2 lb VOC/hr	CT operating hours firing natural gas during startup. Appendix A contains the definition of startup.
TR CT_{NG}	2.1 lb SO_2 /hr 201 lb CO/hr 86 lb NOx (as NO_2)/hr 30.5 lb PM10/hr 62.4 lb VOC/hr	CT operating hours firing natural gas during transient operations (shutdown, fuel switching, or power augmentation). Appendix A contains the definitions of transient operations
FSNL CT_{NG}	2.1 lb SO_2 /hr 460 lb CO/hr 16 lb NOx (as NO_2)/hr 69.7 lb PM10/hr 142.9 lb VOC/hr	CT operating hours firing natural gas during full speed/no load. Appendix A contains the definition of FSNL.

Determination of Emission Unit Operating Mode For A Given Hour

If two or more operating modes are used on the same CT or CT/HRSG DB (Emission Unit ID#s I-A, I-B, and II-A, II-B) during a one hour period, the largest of the pollutant specific emission rates among the operating modes being evaluated shall be used for data substitution and emissions calculations during that one hour period.

If one or more 15 minute periods during an hour are identified as CT start-up, then the entire hour shall be considered one hour of CT start-up for the purposes of estimating emissions. If one or more 15 minute periods in an hour are identified as CT transient operation, then the entire hour shall be considered one hour of CT transient operation for the purposes of estimating emissions. If a CT transient operation occurs during the same hour as a CT start-up operation, then the entire hour shall be considered CT start-up.